OAH Docket No. 3-
2500-8545-2
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015/GR-94-001

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of
Minnesota Power for Authority to
Change Its Schedule of Rates for
Retail Electric Service in the
State of Minnesota.

REPORT QF_THE ADMINISTRATIVE LAW JUDGE
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STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Power and Light Company, d/b/a Minnesota Power for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota.

FINDINGS QF FACT,
CONCLUSIONS OF LAW
AND RECOMMENDATIONS

The above-entitled matter came on for hearing before Administrative Law Judge Allen E. Giles. Prehearing conferences were held on February 18 and June 8, 1994 in the Large Hearing Room of the Minnesota Public Utilities Commission, 121 Seventh Pl ace East, Suite 350, St. Paul , Minnesota. Public hearings for consideration of the matter were held in Little Falls, Minnesota on May 2, 1994; in Park Rapids, Minnesota on May 3, 1994; in Grand Rapids, Minnesota on May 4, 1994; in Eveleth, Minnesota on May 5, 1994; and in Duluth, Minnesota on May 20, 1994. Evidentiary hearings were held in Room 407, Federal Building, Duluth, Minnesota, June 13-16 and 20-21, and in St. Paul in the Large Hearing Room of the Minnesota Public Utilities Commission, Metro Square Building, Suite 350, 121 Seventh Place East, St. Paul, Minnesota on June 23-24 and 27-29, 1994.

Parties participating in this proceeding include the following: Minnesota Power and Light Company (also hereinafter referred to as "Minnesota Power", "MP" or the "Company"); the Minnesota Department of Public Service (hereinafter also referred to as the "Department" or "DPS"); the Minnesota office of Attorney General (hereinafter also referred to as "OAG"); the Minnesota Senior Federation, Northeastern Coalition (hereinafter also referred to as the "Senior Federation"); the Large Power Intervenors consisting of Eveleth Taconite Company, Hibbing Taconite Joint Venture, Inland Steel Mining, Blandin Paper Company and USX Corporation (hereinafter collectively referred to as the "Large Power Intervenors", "LPI" or "LP"); Eveleth Expansion Company (hereinafter also referred to as "Eveleth"); the Large Light and Power Customers consisting of Diamond Brands, Inc., Georgia Pacific Corp., Lamb

Weston/RDD., Midwest Timber, Inc., North Star Steel, St. Gabriel's Hospital,
Upper Lakes Food, Inc., USG, ME International, Land O'Lakes (hereinafter collectively referred to as the "Large Light and Power Group" or the "LLP");
and the Potlatch Corporation (hereinafter also referred to as "Potlatch").

Appearances: Mr. Samuel L. Hanson, Attorney at Law, 2400 IDS Center, Minneapolis, Minnesota 55402; Messrs. Johannes W. Williams and David J. McMillan, Attorneys at Law, Minnesota Power, 30 West Superior Street, Duluth,
Minnesota 55802, appeared for and on behalf of Minnesota Power; Mr. David F.

Boehm, Attorney at Law, 2110 CBLD Center, 36 East Seventh Street, Cincinnati, Ohio 45202, appeared for and on behalf of the Eveleth Expansion Company; Mr. Laurance R. Waldoch, Attorney at Law, 4200 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402, appeared for and on behalf of Potlatch Corporation; Mr. James D. Larson, Attorney at Law, 1100 One Financial Plaza, 120 South Sixth Street, Minneapolis, Minnesota 55402, appeared for and on behalf of the Large Light and Power Group; Mr. Robert S. Lee, Attorney at Law, 1600 TCF Tower, 121 South Eighth Street, Minneapolis, Minnesota 55402, appeared for and on behalf of the Large Power Intervenors; Mr. Brent Vanderlinden, Assistant Attorney General, Suite 1200 NCL Tower, 445 Minnesota Street, St. Paul, Minnesota 55101-2130, appeared for and on behalf of the Department of Public Service; Mr. Eric F. Swanson, Assistant Attorney General, Suite 1200 NCL Tower, 445 Minnesota Street, St. Paul, Minnesota 55101-2130, appeared for and on behalf of the Attorney General's Office; Ms. Susan Ginsburg, Attorney at Law, P.O. Box 425, Duluth, Minnesota 55802, appeared for and on behalf of the Minnesota Senior Federation Northeast Coalition; Ms. Susan Mackenzie, Messrs. Louis Sickmann, Stuart Mitchell and Bret Ekness, Suite 350, Metro Square, 121 Seventh Place East, St. Paul, Minnesota, appeared in a neutral capacity on behalf of the Minnesota Public Utilities Commission.

Notice is hereby given that, pursuant to Minn. Stat. 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 20 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, 160 East Kellogg Boulevard, St. Paul, Minnesota 55101. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. If desired, a reply to exceptions may be filed and served within ten days after the service of the exceptions to which reply is made. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply, and an original and 14 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

STATEMENT OF ISSUES

Whether Minnesota Power should be permitted to increase its rates for retail sales of electricity within the State of Minnesota by $34,348,800 in annual revenues, which it requested, or by some lesser amount, or not at all? If so, what should the amount be and how should it be apportioned among various classes of ratepayers. While addressing these overall questions, subissues as directed by the Commission will also be addressed including:

Is the rate design proposed by the Company just and reasonable, are the Company's proposed capital structure and return on equity just and reasonable; is the Company's proposed external funding mechanism for post-employment benefits other than pensions (PBOPs) just and reasonable, is the Company's proposed recovery of incentive compensation just and reasonable, is recovery justified by demonstrated or projected effects on labor productivity, is the Company's proposed conservation cost recovery charge just and reasonable?

Based upon all of the proceedings herein, the Judge makes the following:

FINDINGS QF FACT

I. PROCEDURAL BACKGROUND

A. Notice and Hearings

1. On January 3, 1994, Minnesota Power filed with the Minnesota Public Utilities Commission (hereinafter also referred to as the "Commission") a petition pursuant to Minn. Stat. 216B.16, subd. 1 (1992) seeking authority to increase its Minnesota retail electric rates by $34,348,800 or 11.78% on an annual basis. The Company also filed a petition for interim rates in which it sought to increase its present revenues by $20,133,135 or 7.09%.

2. By Order dated February 7, 1994, the Commission pursuant to Minn. Stat. 216B.16, subd. 2 (1992) accepted Minnesota Power's filing for a general rate increase, suspended the proposed rates, and initiated an investigation to determine the reasonableness of the proposed rates.

3. On February 7, 1994, the Commission issued a Notice of and Order for Hearing directing that a contested case proceeding pursuant to the Administrative Procedure Act, Minn. Stat. 14.57-14.62 (1992) be held on the reasonableness of the rate changes proposed by Minnesota Power.

4. On February 25, 1994, the Commission issued an Order pursuant to Minn. Stat. 216B.16, subd. 3 (1992) authorizing Minnesota Power to collect as interim rates $20,133,135 in additional revenues or 7.09% of revenues over current rates for service rendered after March 1, 1994. Interim rates are presently being collected subject to refund of any revenues collected in excess of the final rates to be determined by the Commission.

5. Petitions to intervene in-this proceeding were filed pursuant to Minn. Rules, pt. 1400.6200 (1991). The following were made parties to this

proceeding: the Minnesota Department of Public Service; Power; Eveleth Expansion Company; Potlatch Corporation; the Large Light and Power Group; the Large Power Intervenors; the Department of Public Service; the Office of Attorney General; the Minnesota Senior Federation Northeast Coalition; Boise Cascade Company; and the Energy CENTS Coalition. The Energy CENTS Coalition withdrew from the proceeding as a separate intervenor and submitted testimony supporting the Senior Federation.

6. On March 9, 1994, the Administrative Law Judge issued a Prehearing Order establishing the hearing schedule and procedural guidelines governing the conduct of the case. The Prehearing Order scheduled informal public hearings which were held at the following locations on the dates indicated:

Date	Time	Location	Attendance/speakers
May 2	7:00 p.m.	Little Falls	63/1
May 3	7:00 p.m.	Park Rapids	16/1
May 4	7:00 p.m.	Grand Rapids	14/0
May 5	1:30 p.m.	Eveleth	18/2
May 5	8:00 p.m.	Eveleth	74/2
May 20	1:30 p.m.	Duluth	75/18
May 20	7:00 p.m.	Duluth	54/1

The Prehearing Order also scheduled formal evidentiary hearings from June 13 to July 1, 1994 commencing at the Federal Courthouse in Duluth, Minnesota and concluding at the Public Utilities Commission in St. Paul, Minnesota. Forty-two witnesses prefiled testimony and/or testified during the evidentiary hearings. The Prehearing Order established a post-hearing briefing schedule requiring Initial and Reply Briefs be filed on July 25 and August 3, 1994, respectively.

B. Reopening the Record for Additional Evidence

7. On August 15, 1994, Minnesota Power filed a Motion to Reopen the Record for the purpose of filing additional evidence relating to the reopening of National Steel Pellet Company, a taconite mining facility located in Keewatin, Minnesota. A hearing on the Motion was held on August 26, 1994. The Motion was granted by the Judge and the Order Reopening Record and Extending Period for Suspension of Rates was issued on August 30, 1994. As a part of the Order granting the Motion, the Judge also extended the ten-month statutory period by two weeks, from November 3, 1994 to November 17, 1994 pursuant to Minn. Stat. 21B.16, subd. 1a(a) (Supp. 1993). On September 9

1994, the parties filed with the Administrative Law Judge a document entitled Stipulation for Order Reopening the Record. The Judge hereby incorporates the entire Stipulation, including attachments, Exhibits A, B, C and D, into the record of this proceeding, and for reference purposes will refer to the document as the "Stipulation". On September 16, 1994, the Company also filed work papers showing the underlying basis for the numerical financial impact of the Stipulation. The record closed upon receipt of these final documents.

8. According to the Stipulation, the parties have agreed that if the Commission approves the electrical service agreement for National, the test year revenue requirement will be reduced by $2,349,092. In agreeing to this revenue requirement adjustment, the parties do not agree to the underlying class apportionment methodologies employed by the Company. The Stipulation also indicates that the Large Power Intervenors and Eveleth have opposed the

electrical service agreement between Minnesota Power and National in comments filed with the Commission.

9. The Judge will leave for Commission staff the function of merging into the record the exact numerical financial impact of the Stipulation. Upon review of the Stipulation, the Judge finds the agreement reasonable and appropriate and recommends that the Commission accept it. The Judge will address the parties' disagreement regarding revenue apportionment among the classes in the section of this Report that addresses rate design.

II. PARTIES

A. Minnesota Power

10. Minnesota Power and Light Company is a private investor-owned company having a diversity of business operations. MP owns and operates electric, gas, water and waste water utilities. The Company's other major operations include coal mining, paper recycling and manufacturing, and investment and financial services. Minnesota Power's oldest and largest business operation is providing electrical service in northern Minnesota and northwestern Wisconsin.

11. The Company is authorized by the Commission to sell electricity at retail within a 26,000-square-mile exclusive service area in north and central Minnesota. Minnesota Power supplies retail electric service to approximately 110,000 customers residing in cities, towns and rural areas within its assigned service area. The largest city served is Duluth with a population of approximately 85,000. The Company also provides wholesale electric service to 13 municipal distribution systems and to a wholly-owned subsidiary that provides electrical service at retail to customers in northwestern Wisconsin.

12. Minnesota Power delivers electrical service according to a schedule of rates for the following customer rate classes: Residential, General Service (includes small business), Large Light and Power, Large Power, Municipal Pumping, Lighting, Dual Fuel, and Large Power Interruptible. The Company's Large Power class consisting of approximately ten customers engaged in taconite mining or paper pulp production account for approximately 54% of the Company's current revenues. The revenues from the Large Power class customers when combined with the other large industrial customer class, Large Light and Power, amount to approximately 70% of the Company's current revenues.

13. The current proceeding represents Minnesota Power's first general rate case since 1987 and only the Company's second general rate case since 1981. Although the Company requested an annual rate increase of over $4,000,000 in the 1987 proceeding, the Commission ordered the Company to decrease its rates by over $8,000,000. In the Matter of Minnesota Power Company, Docket No. E-015/GR-87-223, Order After Reconsideration and Rehearing (May 16, 1988). The current proceeding represents Minnesota Power's first potential general rate increase since the conclusion of the 1981 rate case.

B. Participating Intervenors

14. The Minnesota Senior Federation-Northeast Coalition is a grass roots membership-based citizen organization, consisting primarily of people over the

age of 55, but also including younger people, in the Duluth area, Lake and Cook Counties, southern St. Louis County, and northeast Carlton County. The Senior Federation directly represents over 5,500 individual dues-paying members who have fixed low and moderate incomes, and over 50 affiliated senior citizens clubs. The Senior Federation also purports to represent all of Minnesota Power residential customers of fixed low and moderate incomes.

15. Attorney General Hubert H. Humphrey, III is statutorily charged with representing and furthering the interests of residential and small business utility customers in matters before the Minnesota Public Utilities Commission involving utility rates and adequacy of utility services to residential and small business utility consumers. Minn. Stat. 8.33, subd. 2 (Supp. 1990) The Attorney General is entitled to intervene as of right and to participate as an interested party in matters pending before the Commission which affect the distribution of public utility services to residential and small business utility consumers. Minn. Stat. 8.33, subd. 3 (Supp. 1990).

16. The Minnesota Department of Public Service has an affirmative obligation to participate, representing the general public interest, in proceedings before the Commission. The Department has an obligation to investigate and enforce, on behalf of the general public interest, the standards and requirements imposed on a public utility by the Minnesota Public Utility Act. The Department intervenes as a matter of right in proceeding before the Commission pursuant to authority contained in Minn. Stat. 216A.07 (1992).

17. The Large Power Intervenors are taconite mining companies and paper manufacturers that use large amounts of electricity in their industrial processes. The Large Power Intervenors include: Eveleth Taconite Company, Hibbing Taconite Joint Venture, Inland Steel Mining, Blandin Paper Company and USX Corporation. The Large Power class dominates Minnesota Power's retail electric sales and consumption by accounting for approximately 54% of revenues while taking 64% of MP's jurisdictional output. For a perspective on the significance and size of the Large Power Intervenors, it should be noted that in 1993 USX Corporation consumed more electricity and paid more for service than all Minnesota Power residential customers combined.

18. The Large Light and Power group are large industrial and commercial businesses that are part of the Large Light and Power class of customers. Approximately 16% of Minnesota Power's retail electric sales were purchased by customers in this class. The specific Large Light and Power group members are as follows: Diamond Brands, Inc., Cloquet; Georgia Pacific Corp., Duluth; Lamb Weston/RDD, Park Rapids; Midwest Timber, Inc., Two Harbors; North Star Steel, Duluth; St. Gabriel's Hospital, Little Falls; Upper Lakes Food, Inc., Cloquet; USG, Cloquet; ME International, Duluth; and Land O'Lakes, Browerville.

19. Potlatch Corporation is a publicly owned, diversified forest products company with manufacturing facilities which convert wood fiber into various wood products such as pulp and paper products. Potlatch Corporation has manufacturing facilities located in Cloquet, Brainerd, Bemidji, Cook and Grand Rapids. Potlatch is a Minnesota Power customer taking service in both the Large Light and Power class and the Large Power class. In 1993, Potlatch paid approximately $8 million for electrical service from Minnesota Power. over the past 15 years, Potlatch has invested over $400 million in its

Minnesota operations and anticipates investing more than $500 million over the next few years in Minnesota for modernization and expansion of its pulp mill in Cloquet.

20. Eveleth Expansion Company, along with Eveleth Taconite Company, own and operate taconite-producing facilities known as Eveleth Mines. These consist of two taconite mines -- Thunderbird North and Thunderbird South -- as well as a concentrating and pelletizing facility known as the Fairlane Plant. Eveleth Mines is a customer of Minnesota Power on the Large Power rate. In 1993, Eveleth spent $16,589,000 for power and produced 3.139 million tons of taconite pellets. Eveleth is a so-called "high cost producer" of taconite. Because Eveleth has been financially unwilling to continue the risk of long-term takehome pay contracts, in 1990 Eveleth gave Minnesota Power its four-year notice of contract cancellation. Cancellation of the contract will be effective on December 31, 1994.

III. PROOF OF REVENUE REQUIREMENTS

21. A major issue in this rate proceeding is what level of revenue is required by Minnesota Power for the provision of electrical service in Minnesota. A utility's revenue requirement is the level of revenues necessary for delivery of efficient, adequate and economical service that at the same time maintains or preserves a utility's sources of capital. Northwestern Bell Telephone Company v. State, 216 N.W.2d 841 (Minn. 1974). Whether a utility's revenues are adequate is determined by closely examining a utility's operating experience during a test period having representative levels of revenues, expenses, rate base and capital structure. Northwestern Bell Telephone Company v. State, 253 N.W.2d 815 (Minn. 1977). As a utility seeking a rate change, Minnesota Power has the burden of establishing that its revenue collections during the test period are inadequate to maintain efficient delivery of service and inadequate to preserve Minnesota Power's sources of capital. Minn. Stat. 216B.16, subd. 4 (1992).

22. The Minnesota Supreme Court has described a public utility's burden of proof as follows:

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. 216B.16, subd. 4 (1986). Preponderance of evidence is defined for ratemaking purposes as whether evidence submitted, even if true, justifies the conclusion sought by-the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished with services at reasonable rates.

Petition of Minnesota Power and Light Company, 435 N.W.2d 550, 554 (Minn. App. 1989).

23. The Administrative Law Judge will make specific findings and conclusions on all issues contested by the parties. Specific findings and

conclusions will also be made with respect to the issues the Commission has directed for evaluation, regardless of whether the issues are contested.

IV. Test Year

24. Minnesota Power has proposed January 1, 1994 - December 31, 1994 as the test period to be used as the basis for determining its revenue requirements for providing retail electric service. Minn. Rules, pt. 7825.3100, subp. 17 suggests that any representative 12-month period "selected by the utility" can be used as the test period. Therefore, the Company's proposed test year to be used for evaluating representative levels of rate base, operating income and capital structure is found to be reasonable.

V. Test Year Rate Base

25. Rate base is a measure of the capital supplied by investors to acquire facilities used for delivery of utility services. Northwestern Bell Telephone Company v. State, 253 N.W.2d 815, 818 (Minn. 1977). Minnesota Power's investors are entitled to an opportunity to earn a fair rate of return on the property used for delivery of retail electric service in Minnesota.

26. Minnesota Power proposed a 1994 test year adjusted rate base of $483,725,599. The DPS proposed adjustments to the Company's Working Capital Requirements.

27. The Department proposed an adjustment to working capital requirements relating to prepayments. The Department proposed exclusion of $774,464 to reflect non-regulated prepayments that had not been previously excluded by the Company. Minnesota Power agreed to this adjustment.

28. The DPS also proposed adjustments to cash working capital to reflect the Department's recommendation regarding test year operating and maintenance expenses ("O&M expenses"). The O&M expense adjustments required an adjustment of cash working capital by applying Minnesota Power's lead lag study results to the DPS adjustment to O&M expenses. Minnesota Power accepted the Department's proposals. As a result of the Department's proposals, working capital requirements increased by $529,400. A summary of the Department's adjustments to the working capital requirements is illustrated in the following table:

DPS ADJUSTMENTS TO WORKING CAPITAL REQUIREMENTS

WQrking Capital Requirements	MP Proposal	DPS Adjustment	DPS Proposal
Fuel Inventory	$6,630,885	$0	$6,630,885
Materials and Supplies	$8,503,441	$0	$8,503,441
Prepayments	$8,440,391	($774,464)	$7,665,927
Cash Working Capital			
Operation & Maintenance Expense:			
Fuel	$ 750,590	$1	$ 750,591
Purchased Power	($1,262,813)	($4)	($1,262,817)
Payroll	$1,685,987	($72,360)	$1,613,627
Other Operation & Maintenance	$ 688.868	($29,386)	$659,483
Total Operation & Maintenance	$1,862,632	($101,748)	$1,760,884
Cash Requirements	$ 341,402	$0	$341,402
Ad Valorem & Payroll	($30,581,148)	$1,356,638	($29,224,510)
Income Taxes	($1,082,030)	$48,976	($1,033,054)
Payroll Taxes Withheld	($299,597)	$2	($299,595)
Sales Tax Collections	($23Q.2Q4) ---	($4)	($230,208)
Total Cash Working Capital	($29,988,945)	$1,303,864	($28,685,081)
TOTAL WORKING CAPITAL REQUIREMENTS	($6,414,228)	$529,400	($5,884,828)

29. The adjustments to rate base proposed by the Department and agreed to by the Company are reasonable. Minnesota Power has affirmatively established that the proposed test year rate base, as adjusted by the Department, is a reasonable representation of the value of regulatory assets used for delivery of electrical service during the test year in Minnesota.

30. A test year jurisdictional average rate base of $484,254,999 is appropriate for this proceeding. A summary of the test year rate base is depicted in the following table:

MINNESOTA POWER

SUMMARY OF MINNESOTA JURISDICTIONAL RATE BASE
TEST YEAR ENDING DECEMBER 31, 1994

Utility Plant in Service	1,019,944,215
Accumulated Depreciation & Amortization	379,335,026
Net Utility Plant	640,609,189
Construction Work in Progress	9,390,357
Working Capital	(5,884,828)
Customer Advances	(717,505)
Customer Deposits	(210,334)
Accumulated Deferred Income Taxes	(151,006,839)
Unamortized Rate Case Expense	398,588
Unamortized WPPI Transmission Delivery Charge	(10.12Q,5351
Total Jurisdictional Rate Base	484,254,999

VI. Test Year Operating Income

A. Revenues

31. Minnesota Power indicated in its original filing that it would have revenues totalling $327,535,315 from sales of electricity in the state of Minnesota. The LLP recommended recognition of an additional $404,712 in test year revenues from Lakehead Pipelines as a result of a metering error. Minnesota Power agreed with the proposed adjustment and included the adjustment in its final update of revenue collections for the test year. Minnesota Power proposed $328,811,721 as the final update of revenues for the test year.

32. The Judge finds that Minnesota Power will have test year revenues totaling $328,811,721 from the sales in the State of Minnesota.

1. Bulk Power Sales

33. The Commission approved a tariff offering for Minnesota Power that allowed the Company to offer 100 MW of interruptible power to large power customers. In the Matter of Minnesota Power, Docket No. E-015/M-93-153 (June 17, 1993). Under the Large Power Interruptible tariff, power is sold at a discount of $5.00 off the demand rate charged to Large Power customers. The Company then markets the freed-up firm capacity in order to recover the cost of the interruptible discount. In its Post-Hearing Brief, LP proposes an adjustment that would impute $6,000,000 of bulk sales revenues from the 100 MWs of capacity regardless of what amount of sales revenues are actually obtained. Under LP's proposed adjustment, approximately $4,000,000 in additional test year revenues would be added.

34. Because LP's adjustment was not made until after the trial in LP's post-hearing briefs, it is inappropriate to consider the adjustment. Although LP sponsored several witnesses, not one of those witnesses proposed the adjustment. Reliable testimony in support of or against the adjustment is not contained in the record.

35. The Administrative Law Judge finds that the bulk power sales revenues forecasted by Minnesota Power are reasonable and appropriate.

DISCUSSION

LP proposed the subject adjustment to bulk power sales revenues as a part of its post-hearing brief. It did-not sponsor a witness to affirmatively justify and explain the basis for the proposed adjustment. Insofar as there is "affirmative evidence" on this issue, it comes from the cross-examination of Minnesota Power's witness, Mr. Stephen Scherner. This, of course, is an inappropriate use of cross-examination. Mr. Scherner has not proposed and does not agree with the adjustment being proposed. Proposing a contested adjustment after the hearing is inconsistent with the orderly procedure developed for consideration of issues in this rate application. The Prehearing Order established an orderly process whereby, through pre-filed testimony, all parties knew in advance of the hearing the positions being taken by other parties. By not disclosing this proposed adjustment until after the hearing, LP has denied Minnesota Power an opportunity to address the proposed adjustment through testimony of one of its witnesses. LP has also denied the Commission and the Judge an opportunity to consider the proposed adjustment on a full and complete record. LP should have sponsored a witness on this issue so that a full record could have been developed and the issue properly considered by the Judge and the Commission. As this record now stands, the only testimony in support of this proposed adjustment is the "argument" contained in LP's brief.

Because there is no affirmative testimony in support of the adjustment to forecasted revenues by LP, LP has failed to prove by a fair preponderance of the evidence that it is just and reasonable to make the adjustment. The Judge also specifically finds that LP has failed to properly present the proposed adjustment for consideration in this proceeding.

It is appropriate to treat LP's proposed adjustment to bulk power sales revenues as a challenge to the reasonableness of the Company's proposals. The Administrative Law Judge finds that when a I I capacity sales and capacity purchases are netted against each other, the net result is a benefit to ratepayers of $5,360,050. The Large Power Interruptible rate provides a service requested by Large Power customers and at the same time benefits all other ratepayers by obtaining longer term commitments from Large Power customers.

B. Operating Expenses

36. Minnesota Power proposed test year jurisdictional operating expenses totalling $300,420,702. Numerous adjustments to operating income have been proposed.

1. SFAS 106

37. In December of 1990, the Financial Accounting Standards Board ("FASB") adopted Statement of Financial Accounting Standards ("SFAS") 106 concerning the recognition and measurement of post-retirement benefits other than pensions ("PBOPS"). The statement changed accounting for PBOPS from a pay-as-you-go method (cash basis) to an accrual basis (recognizing the expense

when the employee earns benefits, not when the benefits are actually paid).
Ex. 55, p. 3.

38. In a generic proceeding regarding SFAS 106 (Docket No. U999/CI-92-96), the Commission concluded that the adoption of accrual accounting was appropriate for ratemaking purposes, effective January 1, 1993. The Commission's Order recognized the right to recover in rates the Net Periodic Post-Retirement Costs, consisting of the service cost, the transition obligation and interest costs. In addition, the Order allowed recovery of the deferred amounts (benefits attributable to service during the period from January 1, 1993 until current service costs are recognized in a general rate proceeding, but not to exceed three years), all contingent upon satisfactory proof that the benefit programs were reasonable. Ex. 55, p. 5.

39. Minnesota Power included in test year expenses the annual Net Periodic Post-Retirement Costs and the amortization of the deferred amounts for 1993 and 1994. As to the transition obligation, Minnesota Power proposed

amortization over a 20-year period. As to the 1993 and 1994 deferred amounts, Minnesota Power proposed a five-year amortization period.

40. The amortization periods proposed by MP for the transition obligation and the 1993 and 1994 deferred amounts are reasonable and consistent with previous commission decisions.

41. The Minnesota jurisdictional amount of SFAS 106 expense in the test year is $8,228,386 and is comprised of (1) the net increase and the PBOP expense under SFAS 106 in 1994 above the pay-as-you-go expense, and (2) the amortization of the deferral of the 1993 and 1994 amounts. The Minnesota jurisdictional amount of the transition obligation is $45,223,440. Minnesota Power proposes to amortize the transition obligation over a 20-year period which results in a jurisdictional expense of $2,261,172 for the test year. Ex. 91, p. 14.

42. MP provides 75% of the cost of the health care plan for retirees, with the retirees contributing 25% of the cost. Coverage for retirees over 65 years of age is coordinated with Medicare through a Medicare carve-out approach, which provides for a reduction in benefits paid by the plan for all amounts paid or payable by Medicare insurance programs. Minnesota Power's resulting health care costs on a per-participant basis are low compared to many other companies. Ex. 55, p. 8.

43. Minnesota Power's benefit programs are reasonable and prudent.

44. MP proposes to use external funding for the SFAS 106 benefits. The Company has established a Voluntary Employee Benefit Association ("VEBA") to cover union employees so that all contributions are fully tax deductible. A second VEBA was also established to cover non-union employees, to which the Company will contribute the maximum tax deductible amount. The remainder will be placed in a grantor trust which can only make distributions to the VEBA's or similar retirement health plans. Ex. 55, p. 8.

45. MP's external mechanism for funding SFAS 106 benefits is reasonable and prudent.

DISCUSSION

The Department reviewed the Company's SFAS 106 proposals and found them to be reasonable and prudent. No intervenor raised any objection to MP's proposed recovery of post-retirement costs, the external funding mechanism or the 20-year amortization of the transition obligation. Large Power Intervenors and the Senior Federation opposed Minnesota Power's proposed five-year amortization for the 1993 and 1994 deferred amounts. Both intervenors recommended that the Company amortize those amounts over a 20-year period. The Judge has rejected this proposal. Minnesota Power selected a five-year amortization for the subject deferred amount to achieve a balance between its desire to minimize the rate impact and the need to recover the accrual amount from the 1993 and 1994 generation of customers.

The Company's proposed five-year amortization period is reasonable for the following reasons. The 1993 and 1994 deferred cost relate exclusively to utility service provided during those two years and the five-year amortization proposed by the Company increases the likelihood that ratepayers who received service during 1993 and 1994 will pay for the benefits related to that period. In addition, because the 1993 and 1994 deferred amounts are considerably less than the transition obligation ($11,927,377 versus $45,223,440), the rate impact of their amortization can be mitigated through a shorter amortization period. Finally, the five-year amortization period is consistent with a similar commission decision in In the Matter of Northern states-Power Company, Docket Nos. E002/GR-92-1185 and E002/GR-92-1186, where the Commission amortized the deferred 1993 costs over three years while amortizing the transition obligation over 20 years.

2. SFAS-112

46. In November of 1992 the FASB issued SFAS 112, which requires that certain post employment benefits prior to retirement be recorded on an accrual rather than a cash basis. MP's post-employment benefits covered by SFAS 112 are its long-term disability and self-insured workers compensation programs for inactive and former employees and their beneficiaries. Effective January 1, 1994, Minnesota Power changed its accounting method from a cash basis to an accrual basis, consistent with SFAS 112. The accrual amount for the test year is $343,601 for the electric utility. The accounting change also creates a transition obligation allocated to the electric utility totaling $1,639,198. Ex. 55, pp. 9-10.

47. Minnesota Power's initial proposal was to expense the entire transition obligation for SFAS 112 in the test year.

48. The Department opposed the Company's proposal to expense the entire transition obligation in the test year. DPS proposed instead that the transition obligation be amortized over a three-year period to coincide with the Company's amortization of rate case expenses. Ex. 91, pp. 7-10. Minnesota Power accepted the Department's recommendation of a three-year amortization period.

49. It is reasonable to include the SFAS 112 accrual amount for the test year of $343,601 in operating expenses. The transition obligation for SFAS 112 should be amortized over a three-year period.

DISCUSSION

The Senior Federation recommended that the SFAS 112 transition obligation be deferred as a regulatory asset until the Company's next general rate case. Ex. 60, p. 5. The Judge has rejected this proposal for the reasons given by MP. All facts relevant to the implementation of SFAS 112 are currently known and there is no expected future event to which this issue could be appropriately deferred. Deferring the transition amount until the next rate case would not facilitate a timely transition to accrual accounting, but merely delay the transition phase. Because accrual accounting will result in a more accurate matching of benefits with the cost of utility service, there is no reason to delay this transition.

Large Power Intervenors recommend that the SFAS 112 transition obligation be amortized over a 20-year period. Ex. 124, p. 42. The Judge has rejected this proposal for the following reasons. The transition obligation for workers compenation claims and for long term disability payments will be approximately four years and five years, respectively. The SFAS 112 transition amount is considerably less than the SFAS 106 transition obligation; therefore, the rate impact from the transition to accrual accounting for SFAS 112 can be accomplished in a shorter time period.

3. SFAS-109

50. In February, 1992, the FASB issued SFAS 109, which changed the accounting for income taxes from the deferral method (income statement approach) to the asset and liabilities method (balance sheet approach) for evaluating the effects on income taxes that result from transactions that occur during the current year or have occurred in the past. Ex. 55, pp. 10-11.

51. Minnesota Power adopted SFAS 109 effective January 1, 1993. For the purposes of this rate case, therefore, Minnesota Power used a before-tax calculation in the determination of the debt component of the allowance for funds used during construction and for income tax expense. Ex. 55, p. 12. Minnesota Power proposed to amortize over a two year period the increase in accumulated deferred income taxes caused by the increase in the federal corporate income tax rate from 34% to 35%, effective January 1, 1993. (Id.) The impact of this increase for 1994 is $377,195 for the Minnesota jurisdiction. Minnesota Power proposed that this amount be amortized over a two year period, consistent with the period approved by the Commission in the Company's 1987 rate case (where the Commission allowed a two-year period) to reflect a decrease in the corporate income tax rate under the 1986 Tax Reform Act. (Id.)

52. It is reasonable and appropriate to include in operating expenses $377,195, the amortized portion of the increase in federal corporate income tax rates from 34% to 35%.

DISCUSSION

Large Power Intervenors recommended that the SFAS 109 related costs be amortized over a 35-year period. Ex. 124, p. 43. The DPS reviewed this issue and agreed with Minnesota Power's proposal to amortize the impact of this adjustment over a two-year period. Ex. 91, p. 34. In Minnesota Power's 1987 rate case (Docket No. E015/GR-87-223), the Commission decided to return the excess deferred income taxes resulting from the reduction of the federal income tax rate over a two-year period. The Commission found the two-year period to be equitable, since it would most likely return the excess to those who paid it. Ex. 57, p. 5. The same reasoning would support the Company's proposal with respect to SFAS 109 costs.

4. Hibbard Units I and 2 Retirement Loss

53. Minnesota Power proposed that the Commission authorize the deferral of the loss associated with the retirement of Hibbard Units I and 2 in Account 187 for Deferred Losses from Disposition of Utility Plant and that the loss be amortized over a five-year period commencing January 1, 1994. The Company did not request that the unamortized balance be included in rate base.

54. Upon retirement of Hibbard on December 31, 1994, there will remain on the Company's books' net depreciable plant in the jurisdictional amount of

$541,230. This is the amount that Minnesota Power proposes to amortize over the five year period. This proposal is reasonable and appropriate.

DISCUSSIQN

Hibbard Units I and 2 were placed into service in 1931 and 1943, respectively. They were an integral part of Minnesota Power's power supply system until they were placed into cold standby status in 1981 and then recorded in Plant Held for Future Use in April, 1988. The option of restarting Hibbard Units 1 and 2 remained a viable generating option until the Company filed its 1993 - 2007 Resource Plan, accepted by the Commission in June, 1993, when Minnesota Power concluded that the Hibbard units no longer represent a realistic future generation supply option.

DPS reviewed the appropriateness of the retirement of the Hibbard Units 1 and 2 and found that it was cost effective. DPS recognized that the Units had not been fully depreciated and that the loss on the retirement of the Units should be recognized through an amortization over a five-year period. Accordingly, the net depreciable plant remaining for Hibbard Units 1 and 2 upon retirement should be amortized over a five-year period.

5. Hibbard Decommissioning Costs

55. Minnesota Power proposed that the Commission create regulatory assets (Account 186, Miscellaneous Deferred Debits) and liabilities (Account 253, Other Deferred Credits) for the decommissioning costs of Hibbard Units 1, 2, 3 and 4, to be amortized over five years, consistent with the amortization of the undepreciated net plant for Hibbard Units 1 and 2. Minnesota Power did not request the inclusion of any unamortized balance in rate base.

56. Minnesota Power employed Midwest Rail and Demolishing to develop a detailed bid for demolishing the Hibbard station. Although Minnesota Power had transferred the boilers for Hibbard Units 3 and 4 to the City of Duluth, the Company retained ownership of the turbines for Units 3 and 4 and all of Units I and 2. The demolition study concluded that a total plant demolition, with specific assignment of costs to the Minnesota Power owned facilities,

would be significantly lower than the cost of dismantling only the Minnesota Power owned facilities, while maintaining the Duluth facilities. The estimated demolishing costs were $1,409,968. (MP Ex. 47, p. 8).

57. DPS reviewed the estimate for dismantling the Minnesota Power owned portions of the Hibbard units and approved Minnesota Power's proposal. Since the decommissioning of the Hibbard units on a piecemeal basis would be more expensive than on an aggregate basis, DPS concluded that the Company's proposal to amortize the decommissioning costs for all units over the same five-year period is reasonable. The Judge also finds MP's proposals reasonable.

6. Decommissioning of Laskin and Boswell

58. Minnesota Power seeks to increase its depreciation rates for the Boswell and Laskin steam plants to account for the estimates of the costs the Company will incur at the time of decommissioning those plants. Minnesota

Power completed a detailed study of decommissioning costs based upon bids prepared by Midwest Rail and Demolishing. This study estimated that, based upon current requirements for site restoration, decommissioning liabilities will be over $28 million at Boswell and $5.2 million at Laskin. The Company requested recovery of these decommissioning expenses through depreciation rates charged for current service since they benefit current ratepayers who receive service from these facilities.

59. The estimated decommissioning amounts for each plant were determined by multiplying the decommissioning costs times the ownership percentages times the probability factor for decommissioning. Reflecting these decommissioning costs over the remaining life of the Boswell and Laskin units produces annual depreciation expense of $1,207,147.

60. The recovery of decommissioning costs for the Boswell and Laskin units through an annual depreciation expense of $1,207,147 is reasonable and appropriate and consistent with a previous treatment of these costs by the Commission.

DISCUSSION

The Company's treatment of these costs is consistent with the treatment approved by the Commission for similar decommissioning costs for Ottertail Power Company in Docket No. E-017/D-83-2. DPS reviewed the Company's request for the reflection of decommissioning costs in depreciation rates and noted that the Commission had allowed recovery of similar decommissioning costs in the Ottertail Power docket referred to above. DPS concluded that the Company's request for decommissioning costs was appropriate and the Company should be allowed recovery in rates. (DPS Ex. 91, pp. 40-41).

The Large Power Intervenors agreed with the recovery of dismantling costs for the Boswell and Laskin plants, but proposed adjustments reducing the amount of the amortization by using a 54 year life instead of the depreciable lives and reducing the probability of dismantling from 100% for Laskin and 80% for Boswell to 50% for both. The Judge rejects this proposal for the reasons given by DPS. DPS Ex. 93, p. 5.

The remaining book lives, used for ordinary depreciation purposes, should be the same remaining lives used for dismantling expenses. While the useful lives of generating assets are often extended beyond the initial depreciation estimates, such extensions usually require major overhauls or additions. The useful lives used for depreciation purposes should be estimated at a particular point in time, assuming the plant is expectedto remain in service with only minor maintenance requirements. If later overhauls or additions ultimately increase the expected life of an asset, the life should then be revised and depreciation and dismantling accruals adjusted accordingly on a prospective basis. DPS Ex. 93, pp. 5-7.

Following the filing of this rate case, Minnesota Power submitted to the Commission a new Production Plant Depreciation Study for 1994. That study included decommissioning costs. (MP Ex. 49, p. 7, referring to the "Petition for Certification of Depreciation Rates for Production Plant" filed on April 8, 1994, in Docket No. E015/D-94-346). Minnesota Power recommended that the Commission's decision in that depreciation docket be incorporated into this record and reflected in the final rate determination. The Judge notes that the depreciation docket referred to by Minnesota Power is not a part of the record in this proceeding. The Minnesota Administrative Procedure Act requires that the decision issued by the Commission as a result of this rate application be based upon the record developed in this proceeding. Minn. Stat. 14.62, subd. 1. If the decision in Docket No. E-015/D-94-346 is non-controversial and "final", then the Commission can take official notice of it for the purpose of incorporating the results of that docket in this record.

7. Rate Case expenses

61. Minnesota Power's projected rate case expenses were based on an examination of actual expenditures in the most recent case, inflating the projected Commission assessments by 3% per year and reducing professional service expenses to reflect the limited use of outside witnesses in direct testimony. Ex. 47, p. 11. The total expenses equaled $1,170,853, which Minnesota Power proposed to amortize over a three year period, reflecting $390,264 as test year expense and $398,588 as the unamortized balance included in rate base. Ex. 47, p. 12.

62. DPS reviewed these rate case expense calculations and generally agreed with the Company's determination of the total rate case expense level and likewise agreed with the three year amortization period. Ex. 64, p. 62. DPS proposed one adjustment to the test year rate year expense, being a 1.06% allocation of rate case expenses to non-utility activities, for a total adjustment of $12,411, or a reduction of $4,137 to test year rate case expense. Ex. 64, p. 63. Minnesota Power agreed to that adjustment. Tr. Vol. 3, p. 178.

63. The Administrative Law Judge finds that MP's proposal to amortize rate case expenses over a three-year period and place the unamortized balance in rate base is reasonable.

8. Results Sharing/Incentive Compensation

64. Minnesota Power's compensation programs are comprised of three components: Base pay, Results Sharing and incentive compensation. Base pay and Results Sharing apply to all employees, while incentive compensation

applies to management employees only. Ex. 35, p. 4.

65. Base pay is the largest component of employee compensation. Minnesota Power's goal with base compensation is to compensate employees competitively with the external marketplace and to provide for internal equity among all positions. Ex. 35, p. 5. Base pay is adjusted annually. For bargaining unit employees, the annual adjustments are determined by external market data and collective bargaining units. For nonbargaining unit employees, external market data and individual performance dictate the adjustments. Ex. 35, p. 5.

66. In 1992 Minnesota Power and its employees established the Results Sharing Program whereby increases in base pay were reduced in exchange for the opportunity to receive Results Sharing awards based upon the performance of the Company. The Results Sharing awards were not extra or added-on

compensation, but rather were established, in large part, by the contributions of employee participants who placed their "pay-at-risk". Compensation was placed "at risk" by reducing by one percent the base compensation merit increases that had been negotiated or were expected. The same one percent reduction was made in 1993 and an additional 0.5% reduction was made in 1994. This total 2.5% reduction was then used to fund a portion of the "pay-at-risk" component of Results Sharing. Ex. 35, p. 8.

67. Results Sharing is available to all employees of the Company. It provides for annual awards of up to 15% of base compensation, depending upon achievement of certain company financial thresholds and Key Result Area goals involving customer satisfaction, employee safety, environmental compliance and market expansion. Ex. 35, pp. 6-7.

68. While the Results Sharing Program has the potential of awards as large as 15% of an employee's base compensation, Minnesota Power is only seeking recovery in rates for awards at the four percent level (also called the threshold level).

69. "Incentive compensation" consists of two plans for officers and other selected management employees -- the Annual Incentive Compensation Program and the Long-Term Incentive Plan. Ex. 35, pp. 14-15. The Annual Incentive Compensation Program rewards management employees based upon the performance of the Company measured against a peer group of electric utilities and in comparison to the Standard and Poor's 500 Stock Index. This program includes both shareholder measures (i.e. return on average common equity and total shareholder return) and ratepayer measures (i.e. lower rate of growth in O&M expenses per kWh and lower rates).

70. Similar to the Results Sharing Program, the Annual Incentive Compensation Program has been funded in part by reductions in the increases in base compensation, with the participants, in effect, placing a portion of base compensation "at risk". Ex. 35, p. 16. Further, the Annual Incentive Compensation Program is designed so that payment under the Program at the "threshold" level, plus payment of the participant's base compensation and the threshold level award under the Results Sharing Program, will not exceed the market. Ex. 35, p. 16.

71. For purposes of this rate request, Minnesota Power has included in the cost of service the Annual Incentive Compensation awards at the threshold level only. Thus, similar to the treatment of Results Sharing, the intent of this request is to recover in rates the portion of Annual Incentive Compensation that is intended to primarily benefit ratepayers, while charging shareholders with any payment over the threshold level. Ex. 35, p. 16.

72. Elected officers of the Company are also eligible for a Long-Term Incentive Plan. Minnesota Power has not sought any rate recovery for potential awards under this Plan, with all costs being borne by shareholders.
Ex. 35, p. 17.

73. MP is seeking to recover $2,045,737 in test year expenses from ratepayers to fund the Results Sharing Program at the threshold level. MP is
seeking to recover $305,511 in test year expenses from ratepayers to fund MP's Annual Incentive Compensation Plan this incentive program at the threshold level.

74. Because MP's management establishes the financial and non-financial goals which may be revised on an annual basis, management directly influences the employees' ability to receive incentive compensation payments. Ex. 93, p. 4. MP employees can meet all the non-financial goals and still not earn an award if the financial goals are not also met. Because incentive compensation may not be awarded, the DPS proposed that the Company be ordered to return any unpaid incentive compensation to ratepayers in MP's next rate case.

75. It is reasonable and appropriate to include in the cost of service the incentive employee compensation cost of MP's Results Sharing Program and Annual Incentive Compensation Program at the threshold level. However, as a condition of recovery of the incentive compensation, it is reasonable to require that compensation that is not awarded must be returned to ratepayers in MP's next rate case proceeding.

DISCUSSION

The Judge believes that it is reasonable and appropriate for Minnesota Power to have at its disposal tools and mechanisms for motivating and guiding employee behavior so as to achieve increased productivity. This conclusion is consistent with the Commission's Order After Reconsideration in NSP's 1993 rate case. The DPS reviewed Minnesota Power's compensation programs and reached the following conclusions: (1) MP's overall compensation package is reasonable; (2) MP has made a reasonable attempt to demonstrate a relationship between compensation and labor productivity; (3) MP's employees are likely to respond to incentive payments; (4) rate recovery for incentive compensation is justified by projected effects on labor productivity; and MP's proposed test-year level of incentive payments is just and reasonable. Ex. 91, p. 47. The Judge has made no adjustment to MP's test year incentive compensation expenses.

However, the Judge adopts the Department's recommendation that the Commission order MP to return to ratepayers in the next rate case any unpaid incentive compensation recovered in rates. The Department's recommendation is based in part on the Commission's Order After Reconsideration in NSP's 1993 rate case, wherein the Commission stated:

> In the original Order, the Commission expressed strong disapproval of the company's retention of the right not to make incentive payments earned under the plan. The Commission continues to view this as an inappropriate transfer of risk from shareholders to ratepayers and as inconsistent with the test year concept on which rates are based. The Commission will therefore require the company to record all earned but unpaid incentive compensation recoverable in rates under this Order for future return to the ratepayers. This will adequately protect ratepayers' interests and prevent erosion of the test year concept.

Order After Reconsideration, Petition of Northern States Power (December 30, 1993) at 7-8. The Judge finds that the Commission's concerns about transfer of risk and inconsistency with the test-year concept are equally applicable to MP's ability to withhold payment of incentive compensation. In expressing this view, the Judge adopts the analysis and reasoning of the Department regarding MP's incentive compensation proposal resulting in an inappropriate transfer of risk from shareholders to ratepayers.

LPI recommended exclusion of Results Sharing and Annual Incentive Compensation based upon the Commission's Initial Order in the NSP dockets referred to above, wherein NSP's incentive compensation had been disallowed. Ex. 124, p. 24. LPI is no doubt aware that the Commission reconsidered its decision to disallow NSP's incentive compensation proposal. As a result of its reconsideration, NSP's incentive compensation proposals were generally approved. With this in mind, the Judge views LPI's position on this issue as a request that the Commission once again revisit and reconsider this issue. The Judge must apply the current position of the Commission on this issue, which is incentive compensation programs should be included in the cost of service. Finally, the Judge has considered and rejected LLP's recommended exclusion of Results Sharing and Annual Incentive Compensation. (LLP Ex. 76, P. 5).

9. Early Retirement Program

76. The Minnesota jurisdictional impacts of the Early Retirement program would be a cost of $2,808,780 and a savings in compensation expense of $4,550,109, for a net savings in expense of $1,741,329. Ex. 58, p. 3. Minnesota Power proposed to amortize the cost of the program over a 36 month period. This would mean that the test year impact for the Minnesota jurisdiction would be a reduction in compensation expense by $631,960 and an amortization of the plan costs of $390,108, for a net reduction to the cost of service for the test year of $241,852. Ex. 58, p. 2.

77. DPS proposed an adjustment to allocate 10.59% of the cost of the program to non-utility expense. Ex. 59. Minnesota Power agreed to this adjustment. (Tr. Vol. 4, pp. 163-164). Incorporation of this adjustment results in a net reduction to the jurisdictional cost of service for the test year of $283,155.

78. It is just and reasonable to amortize the cost of the Early Retirement program over a 36-month period causing reduction in expenses of $283,155.

DISCUSSION

LLP recommended that the test year impacts of the program be annualized. Ex. 77, p. 2. Thus, even though the Early Retirement Program was effective for only five months of the 1994 test year, LLP would calculate the cost and the savings from the program as though it had had a full 12 month impact on the test year. Ex. 59, fn. 8 and 10. Minnesota Power and DPS, on the other hand, reflected only the five months of costs and savings which can actually be expected to occur during 1994. (DPS Ex. 59, fn. 7 and 9). Since the costs and savings from the Early Retirement Program will actually occur for only five months of 1994, it would be inappropriate to develop the test year cost of service by pretending there were actually 12 months of costs and savings. Such a result would require refunding of interim rates for savings which were supposed to have occurred in the first seven months of 1994, but which did not and could not have occurred. There is no evidence in this record to suggest that the retiring employees were not necessary or useful to Minnesota Power for the period of their employment in 1994, prior to retirement.

Minnesota Power's proposed 36-month amortization was based upon consistency with the treatment of rate case expenses, which are likewise amortized over 36 months. (Tr. Vol. 4, p. 178). The rationale of this proposal was that the amortization period for rate case expenses assumes that Minnesota Power would file a new general rate case at the end of 36 months, and that this cost should be fully collected by the date of that filing and not be perpetuated in rates beyond that filing.

LLP and DPS proposed a 48-month amortization, suggesting that this is the average time until plan participants would reach age 62, when they would be entitled to regular retirement benefits. (LLP Ex. 77, p. 3 and Tr. Vol. 5, pp. 107-108). However, the average age at which Minnesota Power employees retire is actually 60, not 62. (Tr. Vol. 4, pp. 177-178). The three year amortization period is more appropriate and should be followed.

10. Research Expenses/EPRI Dues

79. Minnesota Power seeks recovery of various research expenses for activities conducted by the Electric Power Research Institute (EPRI), by institutions under contract with Minnesota Power and by the Company directly. (MP Ex. 28, pp. 26-27). Minnesota Power's research efforts are designed to develop and demonstrate activities associated with production, transmission and marketing of electricity, to enhance the Company's competitive position through increased efficiencies, to aid regional economic development, to increase market share and to improve product quality. (MP Ex. 28, p. 27). Minnesota Power's cost for research and development is less than one-half of 1% of electric revenues (MP Ex. 28, p. 29).

80. In Minnesota Power's most recent rate cases, the Commission has allowed recovery of research expenses, including EPRI dues, with the exception of the portion of EPRI dues which could be allocated to nuclear programs. (MP Ex. 28, p. 29). Large Power Intervenors propose that a similar nuclear expense allocation be eliminated from expenses in this proceeding to be consistent with and conform with the Commission's Order in MP's 1987 rate case.

81. MP has made an affirmative showing on the record of this proceeding

that all the research expenses/EPRI dues are appropriate and provide benefits to ratepayers. Therefore, it is just and reasonable to include all such expenses in the cost of service.

DISCUSSION

Minnesota Power has made an affirmative showing that ratepayers receive benefits from research expenses/EPRI dues, including nuclear research. In this proceeding, no party, including the Large Power Intervenors, has made any effort to challenge MP's evidence on this issue. Minnesota Power has made the following unchallenged claims.

The Company cannot derive the benefits from EPRI membership unless it is a full member. For the test year it does not have the opportunity to designate where its dues will be used, or to exclude nuclear research. Minnesota Power showed a benefit to cost ratio of 11:1 in the 1989 EPRI benefit analysis, for savings and cost avoidance of $16 million. (MP Ex. 28, p. 30). Another study estimated annual benefits over a five year period to range between $3 and $13 million, with benefit to cost ratios ranging from 3:1 to 13:1. (Id.) These benefits outweigh the costs, even including those costs that might be allocated to nuclear research. EPRI's nuclear research projects have also been applied to non-nuclear generation facilities to directly benefit Minnesota Power. (MP Ex. 28, p. 31). EPRI has contributed to Minnesota Power's efforts to reduce cost by providing a wealth of research which would otherwise be prohibitively expensive and by providing services that have enabled Minnesota Power to save money. (MP Ex. 28, p. 32).

11. Adjustments to Conform with the 1987 Rate Case

82. Large Power Intervenors proposed a number of adjustments as being necessary to be in conformance with the Commission's Order in Minnesota Power's 1987 rate case. LP proposes that the following adjustments be made:

item	Proposed Retail Adjustment
Financial Communications	$ 31,306.00
Printing Stock Certificates	$ 6,991.00
Financial Communication/Meetings	$ 31,255.00
Legislative Monitoring	$ 102,231.00

83. The Administrative Law Judge finds that the Large Power Intervenors have failed to prove that the adjustments should be made.

DISCUSSION

Upon consideration, the proposed adjustments are inappropriate for the following reasons:

As to printing stock certificates, while the Commission excluded the entire amount in its Initial Order in 1987, on reconsideration the Commission found that Minnesota Power must issue new stock certificates as a result of the daily trading of its stock and that this was an integral part of its financing through public ownership. It therefore allowed full recovery of the utility portion of this expense. (Order After Reconsideration dated May 16, 1988, E015/GR-87-223).

As to financial communications, while the Commission excluded this cost in its Initial Order, upon reconsideration it agreed that communications with the investment community also benefit ratepayers and promote financial flexibility. Accordingly, it allowed the utility portion of this expense. (Order after Reconsideration, p. 6). Similarly the Commission, on reconsideration, allowed the utility portion of financial mailing lists. (Order After Reconsideration, p. 7). (MP Ex. 49, p. 9).

As to legislative monitoring, these are not lobbying expenses, but relate solely to the monitoring of legislative proposals. This activity is in the best interest of ratepayers and is necessary for the provision of electric service, since the Company must analyze and develop positions on public policy issues that relate to electric utility operations. (MP Ex. 49, p. 9). The expenses associated with legislative monitoring are specifically identified in the Company's budgets to show their deductibility for federal income tax purposes, unlike lobbying expenses which are not deductible. (Id.)

12. Economic DeVelopment Exoenses

84. Minnesota Power included in its test year cost of service a request for recovery of economic development expenses, including the costs of its Economic Development Loan Program and organizational dues. (MP Ex. 1, p. 21). Recent legislation has provided the Commission with authority to allow utility to recover economic development costs from ratepayers. Minn. Stat. 216B.16, subd. 13 (1992). The total Company expense of $1,118,580 was included in the test year. (MP Ex. 47, Sch. G-5). Minnesota Power seeks to recover utility allocated amounts of $957,391.00 for the Economic Development Loan Program and $69,130 for the organizational dues.

85. Because the Economic Development Loan Program is cost effective and beneficial to ratepayers, it is reasonable to allow 50% recovery or $478,695. The organizational dues should be excluded because there is no support in the record that the organizational dues are beneficial in any way to ratepayers.

DISCUSSION

DPS reviewed Minnesota Power's economic development costs and concluded that the Economic Development Loan Program was cost effective. The Department recommended that the Commission allow MP to recover 50%, sharing the cost equally between ratepayers and shareholders. (DPS Ex. 89, p. 3). However, because no ratepayer benefit was established, DPS proposed the exclusion of in organizational dues relating to community development organizations. (DPS Ex. 89, p. 2). The Judge agrees that the DPS exclusions are a reasonable and appropriate compromise. (MP Ex. 1, p. 13).

13. CIP Expenses

86. The Commission earlier approved a deferred debit accounting mechanism and established a Conservation Cost Tracker Account in Minnesota Power's 1987 general rate filing. (MP Ex. 47, pp. 12-13). The Tracker Account includes expenses in excess of those built into the rates incurred

beginning in 1987. As of November 30, 1993, the Tracker Account balance was $7.6 million. (MP Ex. 47, p. 13). For 1994-95, Minnesota Power proposed a two year CIP budget of $11.6 million and anticipates spending $24.4 million over the next four years in conservation investments. (MP Ex. 47, p. 13).

87. The CIP expense level for the test year is $7,535,568. (MP Ex. 47, p. 16). This amount reflects the minimum annual spending level of 1.5% of revenues plus the three year amortization of the CIP Tracker Account estimated balance as of December 31, 1993. (Id.) In its filing, the Company proposed to recover this test year amount through the Conservation Program Adjustment, approved by the Commission on December 16, 1993, as a CIP recovery mechanism effective with January, 1994 cycle one billings and continuing throughout the interim period. The Conservation Program Adjustment is 2.64% times the customer billing, including fuel adjustments, but before the interim rate adjustment, local governments and sales tax. (MP Ex. 47, p. 16).

88. DPS recommended that Minnesota Power include its test year CIP budget in the Company's base rates in this proceeding; that Minnesota Power

should not recover its test year loss margins due to conservation in base rates, but include them in the Tracker Account and recover them through the Conservation Program Adjustment; and that Minnesota Power recover its past conservation expenses, represented by the tracker balance at the end of 1993, through the Conservation Program Adjustment. (DPS Ex. 89, p. 9-11). Minnesota Power accepted these recommendations. (Tr. Vol. 3, pp. 175-177).

89. The Administrative Law Judge finds that Minnesota Power's proposed test year CIP expenses are reasonable.

14. Large Power Contract Cash Payments

90. Minnesota Power provided cash payments to Large Power customers in exchange for amendments to their contracts which extended the term. Each of those cash payments was approved by the Commission for inclusion in the contract amendments, but without any commitment as to how the cash payments would be recognized in a future rate case. (MP Ex. 28, p. 8 and MP Ex. 29, p. 16). A summary of the cash payments is as follows:

Customer	Cash Payment
National	$ 4.48 million
Hibbing Taconite	2.20 million
Inland	1.55 million
Eveleth Mines	.65 million
USX	1.70 million
National	2.00 million
TOTAL:	$12.58 million

The contract extensions assured Minnesota Power of additional fixed cost recovery amounting to over $173 million. (MP Ex. 28, p. 8).

91. Minnesota Power proposed that the cash payments be recognized as an expense during the time that the benefits of the contract extensions are realized. (MP Ex. 28, p. 9). A significant portion of the cash payments had already been fully amortized. Minnesota Power proposes that the annual amortization be included in expense and the unamortized balance be included in rate base. (MP Ex. 28, pp. 9-10 and MP Ex. 47, pp. 24-25).

92. Large Power Intervenors opposed the ratemaking treatment proposed by Minnesota Power, asserting that the expenses should not be included in rates paid by Large Power customers.

93. The cash payments in exchange for contract extensions benefit all of MP's ratepayers. They contribute to rate stability by assuring additional fixed cost recovery of $173 million. Minnesota Power's proposed method for treatment of this expense is reasonable and appropriate.

DISCUSSION

Large Power Intervenors agreed that the contract extensions obtained through the cash payments were favorable to Minnesota Power's ratepayers, but argued that the shareholders received by far the greatest benefit (LPI Ex. 124, p. 36). Large Power also argued that the customers who receive the cash payments should not now be required to recognize them as a cost of the utility affecting their rates. (LLP Ex. 124, p. 37).

The premise that shareholders rather than ratepayers were the beneficiaries of the contract extensions is incorrect. The lack of a contractual commitment assuring future revenues would increase the Company's risk and consequently increase its cost of capital, to be recovered from all ratepayers. (MP Ex. 29, p. 17). Thus, the ratepayers are the primary beneficiaries of the contract extensions, which reduce the Company's risk and reduce the level of rates required to adequately compensate shareholders.

The Large Power customers who received cash payments clearly did so with the understanding that the Company could request recovery of them in rates. Those customers did not negotiate for any exclusion from their own rates and must certainly have recognized that this was a cost that benefitted the entire system. (MP Ex. 29, p. 17). Further, not all Large Power customers received cash payments.

15. Operating and Maintenance Expenses

94. Minnesota Power's cost of service study, as filed, included total company operation and maintenance ("O&M") expense of $250,722,911. (MP. Ex. 47, Sch. B-1, p. 7). Of that amount, the Minnesota jurisdictional portion was $225,307,250. (Id.) The O&M expenses were based upon the 1994 operating budget. (MP Ex. 47, p. 42).

95. Minnesota Power's budget system is the same system that was used and approved in Minnesota Power's 1987 rate case and 1991 rate investigation, with certain modifications that enhance cost separation and reflect changes in the Company's organizational structure. (MP Ex. 44, p. 3).

96. For 1994, Minnesota Power initially established the guideline that the 1994 electric utility O&M budget was not to exceed the July, 1993 current estimate for 1993 expenditures, plus an inflation adjustment of 2.3%. (MP Ex. 45, p. 12). Later in the budgeting process, the guideline was revised to eliminate the 2.3% escalator. (MP Ex. 45, p. 12). The July, 1993 current estimate for 1993 electric utility O&M (exclusive of fuel and purchased power) was $83,760,000. (MP Ex. 44, p. 6). Two adjustments were made to this figure to exclude non-recurring events (CIP expense and SFAS 112 costs), which brought the guideline target for 1994 to $84,762,000. (MP Ex. 44, p. 6 and MP Ex 45, p. 12). During the budgeting process, Responsibility Centers settled on a total O&M budget of $85,496,000 with an offsetting addition for other operating revenue of $811,000. (MP Ex. 45, p.12). When these two figures are netted together, the final budget amounted to $84,685,000, which was below the guideline target of $84,762,000. (Id.)

97. The budget amount was adjusted before inclusion in the cost of

service study for the rate case. Two adjustments were required because the Responsibility Budget included a revenue credit, which was removed from O&M for the cost of service study to be reported in other revenue, and a fuel expense, which was removed from O&M for cost of service purposes to be reported as fuel expense under Account 501. (MP Ex. 45, p. 9). By adjusting for the revenue credit of $2,411,086 and the fuel expense of $1,600,000, and by including the CIP amount of $8,200,000 and SFAS 112 amount of $1,683,000, the total amount claimed in the test year for other O&M became $95,379,457. (MP Ex. 45, pp. 9 and 13). This is a total company figure which can be tied to MP Exhibit 47, Sch. B-1, p. 7 by eliminating the cost of fuel and purchased power, and correcting an error or of $59,059. (LLP Ex 76, p. 14). The $59,059 correction (at total company) relates to an error made by the Company in converting the Responsibility Budget to detail costs by FERC Account. The Company and DPS have corrected for this error by decreasing test year O&M expenses, at the Minnesota jurisdictional level, by $54,198. (DPS Ex. 64, p. 64).

98. DPS reviewed the O&M budgeting process. It specifically examined the question of whether Minnesota Power's 1994 budget complied with the budget guidelines. It found that the 1994 O&M budget guideline target had been $84,762,000, based upon the July, 1993 current estimate of 1993 expenses, with zero inflation. (DPS Ex. 64, p. 52). DPS then calculated an adjusted 1994 budgeted O&M figure of $84,168,371, which was lower than the guideline target. (Id.)

99. DPS recommended three adjustments, each of which was accepted by the Company.

(a) The Company overstated its test year O&M expenses by overlooking some adjustments in the process of converting from the Responsibility Budget to the cost of service study. (DPS Ex. 64, p. 64). This adjustment reduced test year O&M expenses by $54,198. (Id.) The adjustment reflecting the Company's Rebuttal testimony allocation factors is $54,217. (MP Initial Brief, Sch. A-4, p. 2).

(b) The M/OR relating to the preparation and maintenance of the UPA equalization account was mistakenly allocated to a deferred account in the original budget, whereas it should have been expensed in 1994. (DPS Ex. 64, pp. 64-65). This adjustment increased test year O&M expenses by $98,811. (Id.) The adjustment reflecting the Company's Rebuttal testimony allocation factors is $98,915. (MP

Initial Brief, Sch. A-4, p. 2).

(c) A portion of the Administrative and General costs should be allocated to non-utility by applying the A&G assessment factor to non-utility labor. (DPS Ex. 64, pp. 44, 48 and 66-67). This adjustment reduced test year O&M expenses by $154,645. (DPS Ex. 64, p. 67). The adjustment reflecting the Company's Rebuttal testimony allocation factors is $154,699. (MP Initial Brief, Sch. A-4, p. 2).

100. MP's test year O&M expenses including adjustments proposed by the Department are just and reasonable.

101. MP's budgeting process used for this proceeding and the test year budget developed from that process are reasonable and appropriate for this proceeding.

DISCUSSION

LLP recommended that the Commission reduce MP's proposed test year O&M costs by $2.9 million. (LLP Ex. 76, p. 21). That recommendation was apparently based upon the assumption that the Company's 1994 O&M budget exceeded the budget guidelines by $2.9 million. (LLP Ex. 76, p. 20). That assumption was incorrect. It understated the gui deline by using actua I 1 993 other O&M costs, rather than the July, 1993 current estimate, and it overstated the 1994 O&M budget by using the amount included in the test year cost of service, after adjustment, rather than the budget amount. (MP Ex. 44, P. 6; MP Ex. 45, p. 12; DPS Ex. 64, p. 52; Tr. Vol. 3, p. 165; Tr. Vol. 5, p. 110).

In Surrebuttal Testimony, LLP continued to recommend an adjustment by $2.9 million for the total Company, but provided different reasons for the adjustment. (LLP Ex. 77, p. 4). Those reasons were likewise incorrect and support the fact that no adjustment should be made. (Tr. Vol. 3, pp. 1 43-1 44, 1 58 and Vol . 5, p. II 2) .

LLP suggested that Minnesota Power's budget was not reliable for determining test year costs. (LLP Ex. 76, p. 14). That assertion is not supported by the record. All amounts could be tracked and tied out with the final cost of service. One can compare the budget to the cost of service and to prior year Responsibility Budgets and actual charges, by project, by Responsibility Center, by Coordinating Responsibility Center, both on a pre and post-allocated basis. (MP Ex. 45, pp. 9-10). (DPS Ex. 64, pp. 49-56 and Tr. Vol. 5, p. 112). The review of detailed Maintenance and Operating Requisitions (M/ORs) demonstrates that Minnesota Power's budget process is accessible, that its budget documentation is detailed and that the budgeted costs are carefully reviewed before inclusion in the test year cost of service for ratemaking purposes.

LLP suggested that Minnesota Power significantly increased its test year O&M budget, to an amount that is $13.3 million, or 16%, more than the 1993 actual costs. (LLP Ex. 76, p. 19). That 16% increase included $8.2 million in CIP expenses and $1.6 million in SFAS 112 expenses, neither of which truly represented increases in O&M expenses for the test year. (MP Ex. 45, p. 12). This inclusion caused a mismatch. The increase of budgeted 1994 over actual 1993 was less than 1%. (DPS Ex. 64, p. 56 and MP Ex. 45, p. 13).

C. Summary of Test Year Operating income

102. As a consequence of the Findings of Fact relating to test year operating income, the Judge finds that the total jurisdictional income for the test year is $30,319,000, which is summarized in the following table:

MINNESOTA POWER OPERATING INCOME SUMMARY
TEST YEAR ENDING DECEMBER 31, 1994

TOTAL UTILITY OPERATING REVENUE	$ 328,811,721
UTILITY OPERATING EXPENSE	
Operation and Maintenance Expense	
Steam Production	$ 16,856,959
Hydro Production	2,293,737
Other Power Supply	1,448,079
Purchased Power	65,333,559
Fuel	65,058,623
Transmission	2,799,946
Distribution	11,122,066
Customer Accounting	4,112,226
Customer Service and Information	1,578,227
CPA Recovery	7,535,568
Sales	272,278
Administrative & General	
Property Insurance	1,436,577
Research Expense	1,743,223
Advertising	56,963
Rate Case Expense	386,127
Organizational Dues	175,068
SFAS 106	8,228,386
Other A & G	30,398,411
Charitable Contributions	374,554
Bank Commitment Fees	38,853
Interest on Customer Deposits	12,620
Int. on LP Expedited Billings	596,966
Total Adjusted O&M Expense	221,771,812

Depreciation Expense	30,917,137
Amortization Expense	1,090,708
Taxes Other Than Income	36,193,978
State Income Tax	3,268,350
Federal Income Tax	9,993,606
Provision for Def. Income Tax	2,494,642
Provision for Def. Income Tax-Cr	(5,555,580)
Investment Tax Cred.-Feedback	(1,345,581)
AFUDC	(420,554)
Total Utility Expense	298,492,721
TOTAL JURISDICTIONAL OPERATION INCOME	$ 30,319,000

*From DPS Appendix A, p. 7; all DPS expense adjustments adopted except for Early Retirement Amortization, $87,203 must be added to "Other A&G".

VII. OVERALL RATE OF RETURN

103. The overall rate of return represents the percentage which the utility is authorized to earn on its Minnesota jurisdictional rate base. The overall rate of return is determined by an evaluation of the costs of various sources of financial capital according to their arrangement in a capital structure.

104. Minnesota Power proposed an overall rate of return of 9.77%. The overall rate of return is the sum of the weighted cost of capital as demonstrated in the following table:

MINNESOTA POWER PROPOSED
CAPITAL STRUCTURE AND RATE OF RETURN CALCULATIONS
MINNESOTA JURISDICTION
(DOLLAR AMOUNTS IN THOUSANDS)

Class	Amount	Amount As % Of Total	Cost of Capital	Weighted Cost
Long Term Debt	392,512	45.84%	7.20%	3.30%
Preferred Stock	47,564	5.55%	7.03%	0.39%
Common Equity	416.207	48.61%	12.50%	6.08%
Totals	856,283	100.00%		9.77%

A. Capital Structure

105. Capital structure is a financial concept which represents the arrangement of sources of financial capital to a company. The major sources of financial capital are debt and equity. Conceptually, the inquiry is to determine what balance of these capital sources is appropriate for ratemaking purposes as being in the best interest of both the company and its ratepayers. United Telephone Company, Docket No. P-430/GR-83-599, Order After Reconsideration (September 6, 1984); Northern states Power Company, Docket No. E-002/GR-87-670 (August 23, 1988).

106. The Company proposes a significant increase in the common equity portion of its capital structure from 39.48% to 48.61% as compared to the Company's last rate case proceeding. The OAG proposes that a portion of that increase approximately $1 million of common equity associated with the unamortized cost of preferred stock issuance and refinancing expenses be removed from common equity. The proposed adjustment would reduce the Company's common equity ratio from 48.61 to 48.55%.

107. It is reasonable and appropriate to exclude that part of equity associated with the preferred stock call premium.

108. The Judge finds the following arrangement of sources of financial capital as the appropriate capital structure to be used for this proceeding:

MINNESOTA POWER CAPITAL STRUCTURE

Financial Class	Percent of Total
Longterm Debt	45.89%
Preferred Equity	5.56%
Common Equity	48.55%

DISCUSSION

The Judge has chosen to adopt the proposed adjustment recommended by the OAG. According to Minnesota Power, the preferred stock call premiums and issuance expenses immediately reduce the total capitalization on the Company's books through a charge to retained earnings, thereby requiring an adjustment to the Company's equity base. The Judge adopts the argument and reasoning of the OAG. Minnesota Power has undertaken the financing of preferred stock incurring these call premiums in order to achieve a cost savings. Such cost savings, between rate cases, increase the profits for the Company and thereby adds to its common equity. Therefore, it is not clear that the preferred stock call has a net effect of actually reducing common equity and requiring a corresponding adjustment as claimed by Minnesota Power.

Large Power Intervenor witness Mr. Baudino proposed that the equity portion of MP's capital structure be adjusted from the proposed 48-61% to 45% and that this reduction in equity percentage would bring MP in line with the average capital structure for 1993 comparison group selected by him.

The Judge has rejected LP's proposal to reduce the equity ratio percentage from 48.61 to 45.%. Except for the adjustment proposed by OAG that was adopted by the Judge reducing the equity percentage to 48.55, the Judge believes that the ratio is reasonable in relationship to the comparison groups proposed by DPS, OAG and the Company.

B. Cost of Long-term Debt and Preferred StocK

109. The actual cost of long-term debt is 7.20%. The actual cost of preferred stock is 7.03%. No party in the proceeding disputes that these are the appropriate costs for long-term debt and preferred stock.

C. Cost of Common Equity

110. Minnesota Power proposes a 12.5% Cost of Common Equity. This proposal is based upon a Discounted Cash Flow (DCF) market estimate of 11% plus a premium adjustment of 1.5% (150 basis points).

DISCUSSION

As in most utility general rate cases, the estimate of the cost of equity is hotly contested. This is even more true for this case where the Company proposes a risk premium addition of 1.5% onto a DCF-determined 11% estimate of the cost of common equity. The Judge notes that, with the exceptions of the Company's proposed 1.5% upward adjustment and Mr. Ahn's recommendation of 9%, there is not a major disagreement among the parties and that their recommendations are in a range not unreasonable to one another. Minnesota Power sponsored four witnesses who provided substantive testimony regarding the appropriate estimate of the cost of equity: Mr. Arend Sandbulte; Mr.

James K. Vizanko; Mr. David A. Gartzke; and Dr. Roger A. Morin. In addition to the Company, five parties sponsored witnesses who submitted recommendations regarding the appropriate cost of equity. LLP witness Mr. Peter Ahn estimated the cost of equity at 9%. LLP Ex. 81, p. 16. DPS witness Dr. Eilon Amit estimated the market cost of equity to be 11.1%. DPS Ex. 8, p. 5, Tr. Vol. 2, pp. 95 and 105. Large Power Intervenor witness Mr. Richard Baudino estimated the market cost of equity at 10.5%. LP Ex. 126, p. 38. OAG witness Mr. Matthew Kahal estimated the market cost of equity to be 10.85%. OAG Ex. 106, p. 3. Senior Federation witness Mr. Ronald Knecht estimated the market cost of equity at 11.1%. Ex. 137, Schedule 19. Minnesota Power witness Mr. Vizanko estimated the market cost of equity at 11%. MP Ex. 25, pp. 11-12.

1. Flotation Costs

111. Minnesota Power proposes a flotation cost adjustment of three percent to cover the cost of public stock offerings. Those costs include, for example, printing charges, and underwriting costs. Other cost-of-equity witnesses, Dr. Amit, Mr. Kahal and Mr. Knecht, have also included flotation costs in their DCF analyses.

112. The following table depicts DCF calculations with and without flotation costs:

SUMMARY OF DCF CALCULATION WITH AND WITHOUT FLOTATION COSTS

	DCF With Flotation Costs	DCF Without Flotation Costs (%)
Mr. Ahn	9	9
Dr. Amit	11.1	10.70
Mr. Baudino	10.5	10.5
Mr. Kahal	10.85	10.75
Mr. Knecht	10.8	10.602 (approx.)
Mr. Vizanko	11.0	10.703 (approx.)

lEx. 8, p. 4, Tr. Vol. 2, pp. 94-95.

2Ex. 137, p. 25, RLK 19, p. 1 (Revised).

3Ex. 25, p. 12. Flotation costs equal dividend yield divided by one minus the flotation cost percentage.

113. Minnesota Power has no plans for public stock offerings during the test year and, therefore, the Company has no actual representative cost or expenses for stock issuances. Minnesota Power's claim of three percent is theoretical and-is based upon a study by Merrill Lynch of common stock offerings by electric utilities for 1992 to 1993 which indicated that the cost exceeded three percent.

114. It is inappropriate to include flotation costs in the DCF calculation when there are no such costs anticipated during the test year.

DISCUSSION

The Company's claim for flotation costs is theoretical, based upon a Merrill Lynch study of stock issuances of electric utilities for the year 1992-1993. Minnesota Power has no plans for new stock issuances during the test year. It asserts that it is entitled to the flotation cost adjustment regardless of whether an actual stock issuance occurs during the test year. DPS witness Dr. Amit also supported a flotation cost adjustment regardless of whether the stock issuances would be made during the test year. Dr. Amit's reasoning is based on the theory that unless MP or any other utility is allowed to recover its issuance cost, the utility will be denied the opportunity to earn its required rate of return in the future. A formula describing this theory is contained in Dr. Amit's direct testimony.

The Commission has previously rejected theoretical formulations of flotation costs when there was no affirmative proof the costs would be incurred during the test year. In the Matter of Midwest Gas, G-010/GR-90-678 (July 12, 1991). In the 1987 Interstate Power case, E-001/GR-86-34 (May 1, 1987), the Commission rejected a proposed flotation adjustment "when the issuance of the stock is not contemplated". However, where it is established that the utility will incur flotation costs due to public stock issuances during the test year, the Commission has approved a flotation cost adjustment. Northern States Power Company, Docket No. E-002/GR-92-1185, Order After Reconsideration (December 3, 1993).

Mr. Baudino and Mr. Ahn opposed the Company's proposed DCF adjustment for flotation costs. Mr. Baudino testified that the adjustment should be rejected because flotation costs were already being collected from ratepayers in the cost of service and the three percent recommendation was in excess of the Company's actual historical experience. Mr. Ahn testified that it was inappropriate to allow flotation costs from ratepayers when Minnesota Power does not expect any major issuances of common stock.

The Judge has recommended the exclusion of flotation costs because the parties have not articulated a basis for inclusion that is consistent with Commission decisions on this issue.

2. A Fair Rate of Return

115. The determination of a fair and reasonable return on equity involves a balancing of consumer and utility interests. The Commission must ensure that Minnesota Power's authorized rate of return is set at a level which properly balances investor and consumer interests such that MP's investors will not earn excess profits at ratepayers' expense.

116. The United States Supreme Court has defined the proper regulatory

balance between the interests of investors and ratepayers in two major cases.

In Bluefield Waterworks Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), the Court held that a utility's return must be reasonably sufficient to assure financial soundness and provide the utility with the ability to attract capital:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs

> for the convenience of the public equal to that generally being made at the same time..... on investments in other business undertakings which are attended by corresponding risks and uncertainty . . . .

Bluefield, 262 U.S. at 692.

117. In Federal Power Commission v. Hope Natural Gas Co., 320 U.S. S91 (1944), the Court reaffirmed and refined the Bluefield principles The Hope court reiterated that a utility's return should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and attract capital. The Court also stated that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." Hope, 320 U.S. at 603.

118. U. S. Supreme Court decisions have highlighted the signficiance of establishing a return on equity based on current market conditions. For example, in Bluefield, the Court stated: "A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and businesses generally." Son-Also, United Railways & Elec. CO. V. West, 280 U.S. 234, 239 (1930) ("What is a fair return..... cannot be settled by invoking decisions of this Court made years ago based on conditions radically different from those which prevail today. The problem is one to be tested primarily be present day conditions.")

119. In addition, the Court has acknowledged that regulation must attempt to strike an equitable balance between investors ansd ratepayers. In Covington and Lexington Turnpike Road Co. v. Sandford, 164 U.S. 578 (1896), the Supreme Court recognized:

> [S]tockholders are not the only persons whose rights or interests are to be considered. The rights of the public are not to be ignored....... The public cannot properly be subjected to unreasonable rates in order simply that stockholders may earn dividends.

Covington, 164 U.S. at 596. In Federal Power Commission v. Natural Gas Pipeline Company of America, 315 U.S. 575, 62 S. Ct. 736 (1942), this point was reemphasized:

> The consumer interest cannot be disregarded in determining what is a "just and reasonable" rate. Conceivably, a return to the company of the cost of service might not be "Just and reasonable" to the public.

S. Ct. at 753 (Black, concurring).

120. In sum, the Commission is obligated to balance the competing interests of MP's investors and ratepayers in assessing the reasonableness of Minnesota Power's proposed rates.

3. The Discounted Cash FlQw Method

1 21 . The basic formulation of the DCF method is the most widely used approach to rate of return estimates in Minnesota rate cases. OAG Ex. 105 p. 17. The method is intended to estimate what shareholders require as a rate of return, not what return MP will probably or actually earn.

122. This process of estimation is necessary because the future required rate of return for a utility stock cannot be observed directly. OAG Ex. 105, p. 11. It is not based on contract, like bond returns, where the company promises to pay an established interest rate. The sale of common stock involves no promise to pay a contractually fixed rate of return. OAG Ex. 105, p. 12. Yet, obviously, there is a rate of return on equity which investors expect when they decide to purchase shares. The DCF method estimates the expected rate of return.

123. The theoretical foundation of the DCF method is that return on equity expected by shareholders (their required return) is equal to the expected dividend yield (annualized dividend divided by market price per share), plus the expected annual growth in dividends from future earnings. DPS Ex. 6, pp. 3-5.

124. There are two steps involved in the DCF analysis. First, an appropriate dividend yield is calculated. Basically, the dividend yield is the annualized dividend rate divided by the stock's price. The dividend yield is directly observable from market data. OAG Ex. 105, p. 18. Next, the probable growth of dividends is estimated. In contrast to the observable nature of the dividend yield, investor expectations of long-run growth cannot be observed and must be inferred. Consequently, a judgment and analysis, not mere mathematics, is involved in the determination of investor-required growth. OAG Ex. 105, p. 18.

125. Commission precedent has uniformly favored the use of the DCF method:

> The Commission finds that the DCF method is firmly grounded in modern financial theory and has been relied on by NSP, the DPS, the RUD-AG and the MSF in this proceeding and by the Commission in nearly every rate case proceeding since 1978.

Minnesota Power Company, Docket No. E-015/GR-87-223, Findings of Fact, Conclusions of Law and Order, p. 73 (March 1, 1988).

126. The dividend yield is the dividend rate divided by the stock's price. In determining the dividend-yield, the estimate should be relevant for the future regulatory period. In theory, a spot estimate (i.e., the most recent one-day yield) best reflects all current information available to investors and thus that yield is viewed as the best indicator of the expected dividend yield at that time. However, a longer period appropriately smooths the volatility of a spot price.

127. The growth rate component of the DCF formulation is the rate at which prospective investors expect dividends to grow at least through the period of their investment.

128. In computing the growth rate component of the DCF formula, at least three growth rates have historically been considered relevant: (1) the growth rate of book value per share; (2) the growth rate of dividends per share; and (3) the growth rate of earnings per share. Because five and ten-year growth rates are used with regularity in the financial community, a consideration of the historical five and ten-year growth rates and the growth factor selected for measurement is appropriate.

129. The estimated cost of equity is the sum of the growth rate component and the dividend yield.

DISCUSSION

Because the Judge has concluded that the DCF method is appropriate for estimating the cost of equity in this proceeding, any cost of equity recommendation not based on the DCF formulation are, therefore, rejected. This would eliminate the recommendation of Mr. Knecht, who concluded that an estimate of the cost of equity using a DCF formulation alone was inadequate. Mr. Knecht proposed a hybrid DCF formulation that eliminated the weakness of a DCF only formulation. Mr. Knecht entreats the Judge to acknowledge that the various methods for estimating the cost of equity all have inherent biases, and, therefore, it is better to acknowledge those biases and draw a balanced conclusion that incorporates information from a mixture of relatively reliable results. Ex. 137, p. 31. Mr. Knecht's hybrid DCF analysis would eliminate weaknesses and problems that he sees in a DCF alone analysis. The Judge is unpersuaded and unconvinced that Mr. Knecht's hybrid DCF analysis would have any more reliable results than a DCF alone analysis.

Minnesota Power witness Mr. Vizanko's recommendation also comes close to being eliminated for the following reasons. Mr. Vizanko and Minnesota Power's other rate of return witnesses argue that there are no electric utilities comparable to MP. MP's witnesses make this claim as a part of their argument in support of a 1.5% premium adjustment. If MP's assertions were true, a DCF formulation could not be properly applied to estimate the cost of equity for the Company. However, the Judge has found that there are electric utilities comparable (for DCF analysis) to Minnesota Power. The Company asserts that the comparable companies used in Mr. Vizanko's DCF analysis are not in fact comparable to Minnesota Power. This argument weakens the reliability of Mr. Vizanko's DCF analysis.

4. Cost of Equity for Minnesota Power

130. Minnesota Power is a highly diversified company, having investments in paper recycling, water utilities, coal mining and paper production. Investors purchase MP stock not only for its electric utility business, but for the diversified operations as well. Because diversified operations place such an important role in investors' perceptions of the Company, using MP stock price and other data would not yield a reliable cost of equity estimate. It is, therefore, necessary to use a comparison group of electric utilities in order to evaluate the cost of equity for MP's electric utility operations. The Commission used a comparable group analysis for determining MP's cost of equity in the Company's last rate case, where the Commission stated "a DCF-determined cost of equity to a comparable group is a suitable

proxy for the cost of equity for MP's electric utility operations". Minnsota Power Company, Docket No. E-015/GR-87-223 (March 1, 1988).

131. The following table depicts the DCF calculations for Minnesota Power by the expert witnesses and shows the growth and dividend yield components used in the DCF analysis:

SUMMARY OF DCF CALCULATION

	DCF Result	Dividend	Growth Rate %
Mr. Ahn (LLP)	9%	6.5	2.4
Mr. Amit (DPS)	11.1%	ECG-7.57 CCG-7.79 MP- 7.80	ECG-3.55 CCG-3.15 MP- 3.45
Mr. Baudino	10.5%	7.06	3.44
Mr. Kahal	10.85%	7.0	3.5-4.0
Mr. Knecht	10.8%2	?	?
Mr. Vizanko	11.0	7.0	4.0

Includes flotation costs.

2Mr. Knecht believed that a DCF-alone calculation was inadequate.

132. The Judge finds that the estimate of the cost of equity analysis by DPS witness Dr. Amit is well reasoned and the most comprehensive assessment and investigation of MP's cost of equity. Therefore, the Judge adopts Dr. Amit's recommendation (without flotation costs) of 10.7% as the appropriate cost of equity for Minnesota Power.

133. Dr. Amit chose a group of companies whose risk is similar to that of MP-Electric. Dr. Amit's first comparison group consisted of nine publicly-traded electric utilities that survived three "screens", the S & P bond rating, the Beta, and the standard deviation price changes. He referred to this group as the "Electric Comparison Group" or "ECG". His second comparison group consisted of publicly-traded combination electric and gas utilities to account for the fact that MP is a diversified utility. Thirteen companies survived the same three screens used for the ECG. Dr. Amit referred

to this group as the "Combination Comparison Group" or "CCG". Finally, Dr. Amit analyzed MP-Company's return on equity for comparison purposes.

134. Dr. Amit performed three DCF analyses, one for MP-Company (including both the non-regulated and electric operations of MP) and one for each of the two comparison groups. Dr. Amit arrived at his recommended return on equity by using the midpoint of the range of DCF estimates for MP-Company and the two comparison groups, adjusted for issuance costs.

135. Dr. Amit used nine risk measures to compare the investment risk of the two comparison groups, MP-Company and MP-Electric. Dr. Amit concluded that MP-Company's investment risks were slightly higher than his comparison groups' investment risks based on MP-Company's Beta. Dr. Amit explained that Beta was the most direct measure of investment risk and also the measure most readily available to potential investors. He also concluded that MP-Electric was somewhat less risky than his comparison groups based on all the accounting and financial risk measures. Finally, although a direct comparison between MP-Company and MP-Electric was not conclusive based on the accounting and financial risk measures, Dr. Amit concluded that MP-Electric's investment risk was somewhat lower than MP-Company's investment risk, based on his comparison of each to the investment risk of his comparison groups. Ex. 6, pp. 13-15. From this analysis, he concluded that MP-Electric estimated return on equity should be no greater than the estimated return on equity for either of the comparison groups or for MP-Company. In other words, MP-Company's return on equity Is an upper limit for MP-Electric's rate of return. Ex. 6, p. 17.

136. Dr. Amit accounted for all aspects of MP-Electric's investment risk, both through his comparison group selection criteria and through his use of MP-Company for comparison purposes. To determine whether MP-Electric's risks are accounted for in the DCF analysis, the risk screens used by the parties must be examined. Dr. Amit chose risk screens designed to arrive at a group of companies whose investment risk is comparable to or similar to MP's. Each of the three screens used by Dr. Amit is a measure of a different aspect of investment risk. His first screen, the S & P bond rating, eliminates companies with investment risks clearly different from MP's investment risks. Ex. 8, p. 11. Minnesota Power had a S & P bond rating of A-, while Dr. Amit's ECG and CCG had average bond ratings of A and A- to A, respectively. The investment risk that MP faces by virtue of the Square Butte contract also would be reflected in the Company's A- bond rating. Ex. 8, p. 11. Dr. Amit's second screen, the Beta, indicates the degree and direction of change in a stock's return relative to changes in the market as a whole. Ex. 6, p. 11. Finally, Dr. Amit's third screen, Standard Deviation of Price Change, measures the total variability in a stock's return. In addition, Dr. Amit accounted for the difference in investment risk between pure electric utilities and diversified utilities by using his investment risk screens to select two comparison groups representing these two utility types: an electric comparison group and a combination comparison group. Ex. 6, pp. 7-9.

137. The DCF method Dr. Amit applied to the ECG, CCG and MP-Company was

reasoned and straightforward. He estimated the expected growth rate of the dividend for the ECG, CCG and MP-Company by averaging a selected historical growth rate and a selected projected growth rate for each. The selected historical growth rate is the average of five and ten-year historical internal earnings per share (EPS), dividends per share (DPS) and book value per share (BPS) growth rates. The selected projected growth rate for each group is the average of Value-Line five-year forecasts of BPS, DPS and EPS growth rates and Zacks five-year forecasts of EPS growth rates. Ex. 6, pp. 24-34. Dr. Amit calculated the expected dividend yield for the ECG, CCG and MP-Company by applying a growth-related adjustment (increasing current dividend yield by half the expected growth rate) to the current dividend yield based on the most recent available four weeks' data. (4/25/94-5/27/94.) Ex. 8, p. 2. He added the expected dividend yield to the expected growth rate for the ECG, CCG and MP-Company, respectively, to arrive at a required rate of return on equity for each. Then he adjusted his DCF results to recognize the effect of issuance costs. Ex. 6, pp. 36-37; Ex. 8, p. 4. The midpoint of these adjusted rates of return, 11.1%, is Dr. Amit's best estimate of MP-Electric's required rate of return on equity.

DISCUSSION

The Judge believes that the DCF calculation and cost of equity testimonies of OAG witness Mr. Kahal and DPS witness Dr. Amit used appropriate representative data in accordance with past practices of the Commission. Excluding flotation costs, the DCF recommendation of Mr. Kahal and Dr. Amit properly balanced investor and ratepayer interests. The Judge adopts and recommends to the Commission the DCF analysis and cost of equity testimony of Dr. Amit. Dr. Amit provided the most reasoned and comprehensive assessment of the cost of equity. It should be used for ratemkaing purposes in this proceeding.

The Judge specifically finds that Mr. Vizanko's DCF analysis is flawed and should not be adopted for the following reasons. To determine the growth component of his DCF analysis, he used projected growth rates covering periods less than five years. When these inappropriate growth rates are excluded, Mr. Vizanko's growth rate component is well below 3.5%. Ex. 6, p. 58. Mr. Vizanko's dividend yield component does not use the most current dividend yields and was adjusted by the full growth rate instead of one-half of the growth rate. Minnesota Power has failed to prove by a preponderance of the evidence that its proposed DCF calculation should be used for ratemaking purposes in this proceeding.

Minnesota Power cross-examined cost of equity witnesses attempting to establish an update of their DCF calculations. Unless a witness adopted the Minnesota Power update as their own testimony, the Judge rejects all testimony obtained by Minnesota Power on cross-examination which purports to be updates of the various witnesses' DCF analyses. Except for argument of counsel, Minnesota Power has no witnesses that support these updates. Another problem with Minnesota Power's proposed updates is that the purported updates are mechanical applications of DCF analyses without exercise of judgment by a witness. The proposed Minnesota Power updates are not reliable substantive evidence and should not be used for ratemaking purposes.

Minnesota Power has proposed a 150-basis-point (1.5%) "adjustment" to the Company's DCF estimate of 11% for a total requested return on equity of 12.5%. The Company attempts to justify the 1.5% adjustment on the riskiness of its Square Butte purchase power obligations, industrial customer concentration and past good performance. The Judge has rejected the Company's proposed 1.5% adjustment to the DCF determined cost of equity for the following reasons. First and most important, the Company has failed to show that it has risk characteristics different from many other electric utilities. For example, Minnesota Power identifies circumstances that it asserts makes it a more risky electric utility. Those circumstances are, for example, concentration of industrial customers (customer mix) and capacity purchase obligations such as Square Butte. Minnesota Power has made no effort to show whether other electric utilities have these same risk characteristics. By failing to make this effort, the Company has failed to show that it has characteristics that make it unique.

Another reason to reject the 1.5% adjustment is that Minnesota Power has failed to demonstrate that financial market data captured in the DCF analysis do not incorporate the subject risk characteristics. Most of the evidence presented suggests that financial market data captured in the DCF analysis does include the risk characteristics identified by Minnesota Power.

The Judge also adopts the testimony of Dr. Amit, Mr. Knecht and Mr. Kahal on whether or not the 1.5% adjustment is appropriate in this proceeding.

Minnesota Power witness Mr. David Gartzke includes in his prefiled Rebuttal Testimony, statements which the Judge considers unreliable hearsay. The statements address the riskiness of Minnesota Power electric operations as compared to Minnesota Power consolidated operations. Without offering affirmative evidence, Minnesota Power's witnesses assert repeatedly that MP-Electric operations are more risky than MP-Consolidated operations. Mr. Gartzke purports to offer the testimony of bond rating agencies regarding the bond rating of MP-Electric as compared to MP-Consolidated based on his conversations with officials connected with those bond rating agencies. The Judge rejects this rebuttal testimony because the issue of the riskiness of MP-Electric as compared to MP-Consolidated is far too important to be decided by the out-of-court assertions of persons not participating in this proceeding. The addition of this hearsay does not advance proof on this issue.

5. Cost of Capital Summary

138. The overall rate of return is calculated by multiplying the capitalization ratios by their appropriate costs. The sum of these weighted costs is the overall rate of return on capital. The overall rate of return in this proceeding is found to be 8.88%, based on the following calculation:

MINNESOTA POWER
OVERALL RATE OF RETURN

Class	Percent of $ Amount	Cost Rate (%)	Weighted Cost (%)
Long Term Debt	45.89	7.20	3.30
Preferred Stock	5.56	7.03	.39
Common Equity	48.55	10.7	5.19
Total			8.88

VIII. REVENUE REQUIREMENT AND DEFICIENCY

139. As a consequence of the Findings of Fact regarding rate base, test year operating income and cost of capital, the revenue deficincy of MP is 21,637,115, as hereinafter calculated:

SUMMARY OF REVENUE DEFICIENCY

Test Year Ending December 31, 1994

Average Rate Base	S 484,254,999
Rate of Return	8.88%
Required Operating Income	43,001,844
Test Year Operating Income	30,319,000
Income Deficiency	12,682,844
GROSS Revenue Conversion Factor	1.705611
GROSS Revenue Deficiency	21,631,998

IX. CONCEPTS TO GOVERN

140. It is the intention of the Administrative Law Judge that the concepts set for in the Findings herein should govern the mathematical and computational aspects of the Findings. Any mathematical or computational errors are unintentional and should be corrected to conform to the concepts expressed in the Findings.

X. RATE DESIGN

A. Rate Design Overview

141. After a utility's revenue requirement is determined, the Commission must evaluate the rates the utility proposes to charge its classes of customers for the purpose of establishing an appropriate rate design. Rate design is the process of setting rates which will recover the utility's revenue requirement in a manner that is fair to the utility and to its customers. In general, rates should be designed to meet the following goals:

1. Rates should be designed to provide the utility a reasonable opportunity to recover its Commission-approved revenue requirement.

2. Rates should be designed to promote an efficient use of resources.

3. Rates should promote a relatively stable and predictable revenue source to the utility.

4. Rates and conditions of service should change gradually to ease impacts on the affected customers.

5. Rates should be understandable and easy to administer.

DPS Ex. 149, pp. 2-4.

142. Minnesota Power has the burden of proving that the rate design it proposes is just and reasonable and not unreasonably prejudicial, preferential or discriminatory. Minn. Stat. 216B.03 and 216B.16, subd. 4. If Minnesota

Power does not establish the reasonableness of its proposed rate design, then the Commission must determine a just and reasonable rate design. Minn. Stat. 216B.16, subd. 5.

143. When designing rates, the Commission acts In its quasi-legislative capacity to apportion the revenue responsibility among MP's different customers. The Commission balances several important costs and non-cost factors in carrying out this responsibility and makes "choices among public policy alternatives." Hibbing Taconite Co. v. Minnesota Public Service Commission, 302 N.W.2d 5, 9 (Minn. 1981). In recognition of this quasi-legislative process, the courts have shown substantial deference to the Commission's rate design decisions. This deference results from a judicial awareness that the Commission must apply its discretion and expertise in designing rates. Id,; St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission, 251 N.W.2d 350 (Minn. 1977).

144. Minnesota courts have never articulated the specific factors to be considered in designing rates. However, in Reserve Mining Company y, Minnesota Public Utilities Commission, 334 N.W.2d 389 (Minn. 1983), the court specifically rejected a claim that cost of service represented the paramount factor for consideration in setting rates, stating:

> The appellant's argument that the cost of providing service should be the single most important consideration in the setting of utility rates undervalues the PUC's obligation_to also review and balance non-cost factors when determining revenue responsibilities for different classes of customers. This court has recognized that rate levels for a class must ultimately be the product of many countervailing considerations, including non-cost factors, as well as the results of cost studies.

Id. at 393 (emphasis added).

145. The Minnesota Supreme Court has discussed several relevant non-cost factors, including: the impact a rate design would have on different customers; the customer's ability to pay; the ability to pass on the increased cost of energy to others; and the ability of businesses to realize part of an energy cost increase as an income tax savings. Reserve Mining Company v. Minnesota Public Utilities Commission, 334 N.W.2d 389 (Minn. 1983) Specifically, with respect to the impact of a particular rate design on customers, the court stated:

> One consideration applied by the PUC in its rate determination was the impact a rate change would have on different customers. This factor is appropriate because a precipitous increase in one class's rate when rates charged to other classes are declining, or a decrease in one class's rate when overall costs or marginal costs are increasing, may be unreasonable even though that class is already above the cost of service attributed to it by the appropriate cost of service study.

Reserve Mining Company Y. Minnesota Public Utilities Commission at 393.

146. Among the "costs" the Commission has discussed in designing rates are embedded costs; fixed costs; marginal costs; incremental costs; capacity costs; energy costs; and customer costs. Among the "non-cost" factors the

Commission has considered are: the hardships faced by customers; ability to pay; ability to pass on rate increases; rate shock; and historical continuity of rates.

147. The promotion of efficiency means progressing towards the situation in which all resources are employed in the most productive possible uses. In general terms, this requires that rates should be set at marginal costs, or should deviate from marginal costs in a way that is carefully calculated to result in the greatest net benefit obtainable without strict marginal cost prices. OAG Ex. 116, p. 2.

B. Public Comments

148. The following are the comments received by the Judge either at the public hearings or in letters from Minnesota Power ratepayers.

149. Representative members of Minnesota Utilities Investors (HUI) spoke at the hearings. HUI is an organization of Minnesota shareholders who own stock in public utilities. HUI members were as much as 85% of the persons present at public hearings in Little Falls, Eveleth and Duluth. The Judge estimates that HUI members comprised approximately 60% of the persons attending the public hearings. The HUI members made the following points:

a. There are 300,000 utility shareholders in Minnesota.

b. The typical shareholder is retired, over sixty years old, owns relatively few shares, are low to moderate income families, and use dividends to supplement pensions and social security.

C. A fair and consistent rate of return is essential to such shareholders' livelihood.

d. The transition from a monopoly environment to one of competition and deregulation places Minnesota Power in a disadvantaged financial position. With over 62 percent of MP's revenue stream generated by a few large customers plus a long term take or pay purchase power contract, a higher rate of return on equity than the industry norm is needed to attract investment capital.

e. HUI recommends that MP receive a 12.09 percent return on equity. HUI supports employee incentive compensation and economic development.

150. Not all Minnesota Power shareholders supported the position taken by MUI. Two correspondents, also Minnesota Power shareholders, opposed the

increase, particularly the substantial increase to residential rates.

151. In correspondence, retired seniors on fixed incomes indicated that while an increase at the COLA level may be justified, it was unreasonable for shareholders to expect 12.5% when other returns are much less. Some seniors suggest that the increasing expenses such as real estate taxes, sewer, water, gas, garbage and utilities, accelerate the end of their independence, their ability to live on their own as homeowners and increase in electricity rates will contribute to the end of their independent lifestyles. Many seniors

thought that a 25% increase was too high and that any increase at all should be shared equally by business and residential consumers.

152. One commentator suggested that Minnesota Power's billing practices pose a problem for the City of Park Rapids. Minnesota Power sends a bill for each City meter, even though the City constitutes one customer. This practice places the administrative burden on the City when Minnesota Power could handle it.

153. One commentator spoke on behalf of mid-sized manufacturing businesses. Contracts to provide products typically run from one year to five years in duration. These businesses cannot pass on increases in energy costs due to contracts and market pressures. The proposed rates will increase the electrical costs to one such business by $10,000 a month, beginning in 1995. Minnesota Power has been very helpful in controlling costs by introducing a dual fuel interruptible rate. The interruptible rate power amounts to half of the manufacturer's power demand; and the fixed demand rate power supplies the other half. The fixed demand rate will increase by 10% which is not significant, but the interruptible rate will increase by 35 to 45%. The interruptible rate increase is too much. The increase will force that manufacturer to use the demand rate. Under the demand rate, if demand goes up, the manufacturer is obligated to pay 90% of the higher demand, regardless of usage, for the next 11 months. The commentator supports retention of the existing interruptible rate.

154. Several commentators spoke on behalf of the Senior Federation. They indicated that costs are squeezing retirees on fixed incomes. They indicated that utility costs are especially hard on retirees on fixed incomes. The following is a sample of their comments:

(a) Many older retirees have pensions lower than recent retirees. Many have social security and pension incomes totaling $600 per month or less. The high rate for the first 50 kilowatts is pretty high for poor people. The Minnesota Power shareholders' increase is not justified as compared to the people who are going to be hurt by the rate increase.

(b) Minnesota Power is facing a choice between less profit for its shareholders and raising rates. Minnesota Power would rather keep its profits high. Minnesota Power is shifting cost pressure from the taconite producers to residential consumers.

(c) Minnesota Power is seeking to increase the basic customer charge in addition to its per kilowatt rate. These increases will result in a cost rise of 25% for users of 700 kilowatts per month and a rise of 33.3% for users of 350 kilowatts per month. Minnesota Power is trying to cancel out the lifeline rate by increasing the basic customer charge. Rates go down for people using over 700 kilowatts, discouraging conservation. The largest discounts are for dual fuel rates, which are almost never interrupted. Low and moderate income people subsidize electric heating for wealthy persons and businesses.

(d) One big purpose of the rate increase is to boost Minnesota Power's profit by 25%. Minnesota Power's stockholder report states that their average return on dividends and increase in stock value is 17% per year. Minimum income in this region Is far below the state and national averages.

155. A MUI shareholder speaking in Duluth indicated the risk for investors has increased and the value of Minnesota Power shares has declined 20% over the past few months. The average utility receives 24% of its electrical revenue from industrial customers, however, Minnesota Power receives 62% of that revenue from industrial customers. Eight of Minnesota Power's industrial customers provide most of its revenue. Long-time purchase power contracts provide lower priced electricity for residential customers, but obligates Minnesota Power to pay for the power whether the customer uses it or not. MUI proposes an allowed return on equity of 12.09%. This rate of return is based upon the average increase of 11.44% by commissions across the nation. An additional "flotation adjustment" of .15% and a risk adjustment of .5% are added to the average. MUI maintains that this rate increase meets the intent of the 1923 Bluefield standard.

156. Minnesota Power was criticized by one commentator for not fully utilizing its hydropower reservoir storage system, costing ratepayers $855,000 over the last three years. This commentator asserted that, in 1992, Minnesota Power diverted water around the Jacobs State Park facilities, costing the ratepayers $425,000. In 1993, the diversion of water lost $350,000 for the ratepayers. Due to the lack of rainfall and runoff, only $75,000 was lost to ratepayers. The large quantity of water diverted has caused flooding problems. The Public Utilities Commission should reduce any aggregate rate increase by $285,000 annually to encourage Minnesota Power to use this hydropower resource.

157. One-hundred and ten letters were received by the Administrative Law Judge. All of the letters opposed a rate increase for Minnesota Power. Some of the letters are summarized above, the following concerns were also expressed in those letters:

a. Minnesota Power's management has engaged in improper investment, resulting in a sharp decline in the earnings per Minnesota Power share. Minnesota Power is seeking to correct these investment mistakes through rate increases on consumers.

b. Retirees on fixed incomes who have invested in "dual-fuel" heating cannot afford higher electric rates.

C. Small businesses cannot afford to replace equipment at the rate enjoyed by Minnesota Power. Rate hikes should be limited to the rate of inflation. An 18% rate hike cannot be justified.

d. Retirees need rate increases that are gradual and can be absorbed. A 25% increase creates "rate shock" that is harmful to seniors on fixed incomes who may be forced to choose between a meal and electrical power.

e. The total income for some retirees, including union pensions, leaves them with no savings and dependent on food stamps.

These people cannot afford the rate increases proposed by Minnesota Power.

f. Pensions for retirees will not increase. Cost-of-living adjustments will not cover the increased cost of Minnesota Power's rate increase. Minnesota Power has rejected the option of structuring rate increases to ease the Impact of these cost increases.

C. Class Revenue Responsibility

1. Class Cost of Service Studies

158. The goal of an Embedded Class Cost of Service Study (hereinafter also referred to as "CCOSS") is to allocate projected test year expenses to the classes that cause them to be incurred. DPS Ex. 118, p. 3.

159. Minnesota Power presented an embedded class cost of service study. That study directly assigned certain test year cost by FERC account to specific customer classes if it was clear that the cost was directly attributable to that class. (DPS Ex. 118, p. 9). Other costs that were not directly assignable to a rate class were apportioned to the customer classes by following three basic processes: (1) classification of costs into three components (demand, energy and customer-related); (2) functional assignment of costs into 34 major functions in order to determine which customers are responsible for them; and (3) allocation of the classified and functionalized costs to the various customer classes. (MP Ex. 47, pp. 34-39).

160. Minnesota Power allocated demand-related costs using eight demand allocators. To allocate power supply production costs, Minnesota Power used a methodology referred to as "Capital Substitution, Average and Excess/Probability of Deficiency" (CAPSUB AE/POD). (DPS Ex. 118, p. 12 and MP Ex. 50, pp. 13-14). The CAPSUB AE/POD methodology determines a single demand allocator by, first, segregating demand costs into "capacity-related" and "generation-related"; second, allocating capacity-related power supply production costs using each customer class's responsibility for Minnesota Power's Probability of Deficiency; and, third, allocating the generation-related power supply production costs using an Average and Excess method. (DPS Ex. 118, pp. 12-14 and MP Ex. 50, pp. 13-14).

161. Minnesota Power's embedded class cost of service study was based upon the principles that this Commission has enunciated over the course of several rate cases. The methodologies used to develop Minnesota Power's demand, energy and customer allocation factors in this filing are identical to those approved by the Commission in the 1987 rate case, with three exceptions.

a. Minnesota Power eliminated the procedure of using "normalized" Large Power Class loads instead of budgeted loads, in developing allocation factors. (MP Ex. 50, p. 7; Tr. Vol. 4, pp. 46-47). Since 1988, Large Power customers have negotiated contracts with firm and excess power demands which now reflect those customers' normal operating levels and, therefore, the budgeted usage levels represent the normal load factor levels for this class and need not be normalized. (MP Ex. 50, pp. 7-8; Tr. Vol. 4, pp. 46-7);

b Minnesota Power included Large Power Excess Demands in the Large Power Class for allocation factor purposes. (MP Ex. 50, p. 7). Because the Excess Demand feature of the Large Power Service Schedule was first approved in the 1987 Order, Large Power Excess Demands did not exist until after the 1987 rate case; and

C. Minnesota Power proposed changing the methodology used to develop the allocation factors for allocating conservation expenses, dual fuel interruptible service costs and primary lines. (MP Ex. 50, p. 7).

162. DPS agreed that the three changes in methodology from the 1987 Minnesota Power CCOSS (normalization of LP load, customer-related sales expenses and conservation, dual fuel and primary line costs) were appropriate, with the exception of the allocation of conservation expenses. (DPS Ex. 118, pp. 6-9). As to conservation costs, DPS recommended that they be classified as 15.6% demand-related and 84.4% energy-related instead of 50% energy and 50% demand. Minnesota Power accepted DPS's recommended method for classification of conservation costs based on actual capacity and energy savings, but disagreed with its allocation on demands and energy. (MP Ex. 51, p. 8).

163. In reviewing MP's proposed CCOSS, DPS identified several concerns with MP's methodology. The DPS directed the Company to run their cost study with several modifications proposed by the Department. The resulting cost study is similar to Minnesota Power's cost study but has some significant differences. The Department study indicates that the total embedded demand costs are approximately half as great as MP estimates, while total embedded energy costs are approximately twice the level that MP estimates. DPS Ex. 118, pp. 25-26. The Department's CCOSS is based on the following modifications to MP's proposed cost study:

a. Classify power supply production costs into energy-related and demand-related components based on the Department's stratification method;

b. Classify purchased-power expenses into energy-related and demand-related components based on the stratification method;

C. Separate competitive-rate customers and large power interruptible customers into separate classes; and

d. Allocate conservation costs based on the actual capacity-related and energy-related savings that MP's conservation programs achieve.

DPS Ex. 118, pp. 16-17.

164. The Company's AED/POD methodology provides the best information for allocating capacity-related and energy-related fixed costs, transmission-related costs and energy (variable) costs. It is appropriate to continue the CCOSS methodology for Minnesota Power approved by the Commission in the Company's 1987 rate case.

165. It is appropriate that the Company's Large Power interruptible customers and competitive rate customers be treated as separate classes for CCOSS purposes. Separating these customers into distinct classes will allow better examination of costs and revenues.

166. It is appropriate that conservation costs be allocated based on their resultant capacity and energy savings as proposed by the Department.

DISCUSSION

The Company maintains that its AED/POD method is superior to DPS's stratification method. In the Company's 1987 rate case, the Commission agreed rejecting a similar DPS proposal stating as follows:

> The Commission disagrees with the ALJ that the DPS embedded class cost of service study is superior to that of MP. The record evidence does not show that the DPS peaker-substitution method is superior to the MP CAPSUB method adopted by the Commission in both the 1980 and 1981 MP rate cases. In those proceedings, the Commission found the CAPSUB method properly recognized that a highload factor utility such as MP invests in more costly base load units in response to off-peak energy use, not just system peak needs, and avoided the over-assessment of demand cost to low load factor classes. The Commission reaffirms those findings.

Minnesota Power and Light, Docket No. E-015/GRO87-223, pp. 83-84 (March 1, 1988).

The Department has made no effort to explain its proposal in connection with the proposal rejected by the Commission in the 1987 Minnesota Power rate case. The DPS has not asked the Commission to reconsider and change its view on this issue. For this reason, the Judge believes that DPS has failed to properly present their proposal to the Commission. DPS's assertion that its stratification method has been approved by the Commission for each of the other regulated electric utilities in the state is unpersuasive. The Commission approved the Company's methodology because of characteristics unique to Minnesota Power, i.e., high load factor, investment in costly base load units for off-peak energy use and avoiding over-assessment of demand costs to low load factor classes. In the presentation of its proposal, the Department should have addressed why these matters should not now be of a concern to the Commission. The Department should continue to pursue the application of its stratification method to Minnesota Power. As compared to the CAPSUB methodology, the Department's stratification method is more simple. The quantification of the cost of service is filled with opportunity for error. Any proposal that accomplishes a reliable result while simplifying the process deserves thoughtful consideration. However, on the facts of this case, DPS has failed to demonstrate that its proposal, although more simple, is not encumbered with the potential for error identified by Minnesota Power.

The Judge has concluded that the interruptible and competitive-rate customers should be separated into distinct customer classes. This methodology would allow the Commission and various rate design analysts to examine each class's costs and revenues. Minnesota Power argues that the costs and revenues of these customers can be examined without separating the customers into distinct classes. The Company also argues that the separation would be complicated and would raise difficult issues with respect to the development of allocation factors. MP Ex. 51, pp. 6-7. Minnesota Power's methodology inappropriately assigns the cost and revenues of interruptible and competitive rate customers to all other classes. It is appropriate to establish distinct classes for these categories of customers.

The Judge has rejected Minnesota Power's claim that the allocation of conservation expenses to customer classes should be based on each class's revenues. The Company makes this claim based upon irrelevant associations. The Judge rejects this argument as being unreasonable. On the other hand, the Department's proposal that conservation costs be allocated based on their resulting capacity and energy savings is reasonable and appropriate.

2. Class Revenue Allocation Proposals

167. Minnesota Power has six customer rate classes. Under Minnesota Power's CCOSS, the rates of return by class, under present rates, are as follows:

Minnesota Jurisdiction	Residential	General Service	Large Light and Power	Large Power	Municipal -Pumping	Lighting
5.61%	- 6.34%	8.34%	10.30%	12.68%	8.83%	2.19%

MP Ex. 47, Vol. IV, Sch. C-1, p. 1. Based on MP's CCOSS, there is a substantial underrecovery of costs assigned to the Residential Class relative to all other classes. (MP Ex. 50, p. 18). The underrecovery of costs assigned to the Residential Class is the major rate design issue in this proceeding. Minnesota Power, the Department, Large Power Intervenors, the Large Light and Power Group, Eveleth and Potlatch all recommend dramatic increases in residential rates in order to move the Residential Class rates closer to "cost" as determined by MP's or the Department's cost of service studies. The following is a summary of the proposals made by the parties.

168. Minnesota Power's proposal used three criteria in apportioning its proposed revenue requirement. The first criterion was cost, whereby the

Company proposed to move the rates of return of each class closer to the cost such class imposes on the system. (DPS Ex. 149, p. 5). The second criterion was that any residential rate increase should be moderated to avoid adverse impact. (Id.) The third criterion was to cap initial increases to all customer classes at 150% of the overall increase, with the maximum increase thus being 18%. (Id.) To avoid the disruptive impact that an immediate increase would have on residential customers, the Company proposed that the increase be phased in over three years.

169. Specifically, the Company proposed that residential rates be increased by 25% over a four-year period -- a 7% increase through interim rates; an additional 11% increase with general rates effective on or about January 1, 1995; an additional 3 % increase on January 1, 1996; and a final 3% annual increase on January 1, 1997. (MP Ex. 50, p. 25 and MP Ex. 28, p. 25). The Company further proposed that the 1996 and 1997 increases of 3 % each be distributed to the Large Power and Large Light and Power customers as a credit. (Id.) Thus, under the Company's final position on revenue requirements, the Large Light and Power customers would receive an initial

increase of 11.9%, with credits for the increase in residential rates in 1996 and 1997, while the Large Power Class (excluding Interruptible Service) would receive an initial increase of 5.2%, with credits from the residential rate Increase in 1996 and 1997.

170. Minnesota Power's proposal also called for an increase in General Service rates of 18%, set to equal the initial percentage increase sought for residential customers; an increase for Municipal Pumping of 15.1%, set to provide the same return as General Service; and a zero increase for the Lighting service. Minnesota Power's final proposals for each class are summarized in the following table.

Class	Initial Increase	After Phase-In
Residential	18%	25%
General Service	18%	18%
Large Light & Power	11.9%	10.2%
Large Power	5.2%	3.7%
Municipal Pumping	15.1.%	15.1%
Lighting	0%	0%

171. DPS used four criteria to apportion the revenue requirement among the classes. The first three were the same criteria used by Minnesota Power -- that is, cost, moderation of the increase to residential customers and a cap at 150% of the overall increase. (DPS Ex. 149, pp. 5-6). The fourth of the criteria was that no class that is currently contributing more than its cost of service should receive a greater than average increase by the end of the phase-in period. The Department proposed that the increases for the Residential and Lighting Classes be phased in at 4% per year over four years, and that all noninterruptible classes' revenue responsibilities be reduced accordingly over the same four years. (DPS Ex. 149, p. 7). The Department's proposal for increases to each class was as follows (Id.):

Class	Initial Increase	After Phase-In
Residential	13%	25%
General Service	18%	11.78%
Large Light & Power	14.25%	11.78%
Large Power	7.49%	6%
Municipal Pumping	14.93%	11.78%
Lighting	13.00%	25%

172. As compared with MP's proposal, the DPS's proposal is a more gradual transfer of revenue responsibility. Both MP's and DPS's proposals call for revenue neutral increases in post-test years.

173. LLP proposed that the Commission order Minnesota Power to adopt rate design and revenue allocation procedures that will result in all customer classes paying rates based on the cost to serve. (LLP Ex. 87, p. 7). LLP recognized that maximum increase to any rate class in this proceeding should be limited to 18% to mitigate rate shock and proposed that any deficiency in revenue requirement resulting from that limitation should be assigned to the Large Power Class. (LLP Ex. 87, p. 10). The application of this criteria for setting of the initial final rates resulted in the following increases by class (LLP Ex. 87, P. 10):

Class	
Residential	18%
General Service	3.43%
Large Light and Power	(03.2%)
Large Power	15.84%
Municipal Pumping	1.58%
Lighting	18%

174. LLP proposed that the Commission order the Company to establish a procedure that will insure that rates for all customer classes would be based on cost of service by a specific date in the future. The mechanism recommended for this was the establishment of a revenue credit factor for the Residential and Lighting Classes and a rate surcharge factor for the Large Power Class, with a monthly automatic adjustment mechanism that would reduce both the credit and surcharge factors over a 60 month period, until rates for Residential, Lighting and Large Power Classes would be equal to the cost of serving those classes. (LL&P Ex. 87, p. 15).

175. Eveleth proposed that residential rates be increased by 25% on January 1, 1995, with compounded increases of 10% each on January 1, 1996 and January 1, 1997. (EV. Ex. 72, p. 8). This would result in a cumulative increase on January 1, 1997 of 51.25%. (Id.)

176. LP recommended a seven year Residential Class phase-in plan that would completely eliminate all subsidies to the residential customers by the year 2001. (LP Ex. 133, p. 5). LP recommended that the total residential increase be implemented in approximately equal dollar steps during the seven years 1995 through 2001, except that the first year (1995) increase in dollar terms would be slightly higher than the succeeding six years. (LP Ex. 133, p. 30 and Schedule E). LP recommended first year increases as follows (LP Ex. 133, P. 31):

Class	
Residential	15.76%
General Service	21.88%
Large Light and Power	13.97%
Large Power	5.72%
Municipal Pumping	0.87%
Lighting	32.16%

Residential rates would then increase by about $6 million per year from 1996 through 2001, with each year's additional revenue being distributed to the General Service, Large Light and Power and Large Power Classes. (LP Ex. 133 and Schedule E).

177. OAG recommended that the Commission consider non-cost factors in determining class revenue responsibility. (OAG Ex. 116, p. 6-7). OAG proposed an alternative rate design whereby an even increase of about 10.5% would be given to each of the Residential, General Service, Large Light and Power and Large Power Classes. (OAG Ex. 116, pp. 17-18 and SBC-1).

178. Minnesota Senior Federation described the adverse impact that Minnesota Power's residential rate proposal would have on low income households and senior citizens, but the Senior Federation did not present any alternative proposal for the revenue distribution to the classes. (MSF Ex. 63, pp. 16-21). Senior Federation recommend that the Commission consider various customer assistance programs. (MSF Ex. 74, pp. 3-8).

3. Residential Class Revenue Apportionment

179. All class revenue allocation proposals submitted by the parties in the previous paragraphs represent a major departure from prior Commission policy on Residential Class cost responsibility on the Minnesota Power system. At no time previously has the Commission imposed revenue responsibility on the Residential Class based solely on its cost to the MP system. The Residential Class has been a beneficiary of previous Commission decisions attempting to reflect the cost imposed on the MP system by Large Power customers.

180. Although the Residential Class allocation proposals represent a major departure from previous Commission decisions, not one of the parties has asked the Commission to revisit and reconsider the policy judgments developed by the Commission in Minnesota Power rate case decisions beginning in the 1970s and continuing to Minnesota Power's 1987 rate case.

181. A cost of service study is useful as a starting point and for providing guidance, but the Commission has made its own policy judgments; at no previous time has the Commission allowed costs to serve as a substitute for its judgment. As such, particularly with respect to Minnesota Power, the Commission has considered cost and non-cost factors for determining Residential Class cost responsibility. For example, in Minnesota Power's 1987 rate case, the Commission stated as follows:

> The Commission must caution that a class cost of service study is only a starting point for determining reasonable class revenue responsibility levels . . . . However, such studies have limitations and cannot claim to be precise measures of cost . . . . (O]ther costs and non-cost factors may, and should, be taken into consideration when determining class revenue responsibility.

PC Docket No. E-015/GR-87-223 (March 1, 1988), pp. 84-85. Among the non-cost factors the Commission took into consideration in the 1987 rate case was the economic hardship suffered by all classes, and particularly the Residential Class, in Minnesota Power's service territory.

182. Although Minnesota Power, DPS and the other parties assert that Residential Class rates should be increased "to send proper signals", these parties also acknowledge that the fully distributed cost (FDC) studies of the Department and Minnesota Power have substantial limitations; and that "to send proper signals" cost must be based upon marginal cost.

183. Not all customer classes impose the same risk on Minnesota Power's operations. The Large Power Class has over the years, as compared to other classes, imposed more risk on the Minnesota Power system. The Large Power Class continues to impose more risk on Minnesota Power operations as

demonstrated by the Company's testimony on cost of equity. The cost of financial capital to Minnesota Power is increased because investors view the concentration of large industrial customers as increasing the risk of investment in Minnesota Power stock.

184. The additional cost imposed upon the MP system by the Large Power Class has not been quantified. It would be useful to have such a quantification for the purpose of making a judgment as to whether the cost imputed to the Large Power Class by the Commission over numerous rate cases continues to be appropriate.

185. Although the Residential Class does not impose the same risk on Minnesota Power operations as the Large Power Class, Minnesota Power's CCOSS assumes the same rate of return responsibility for both customer classes.

186. The current revenue apportionment for the Residential Class was purposefully set by the Commission over several rate cases to achieve certain policy goals, an example of which is making every effort to shield the Residential Class from the additional costs caused by the risk imposed upon the MP system by the Large Power Class customers.

187. The parties proposing a substantial increase in the Residential Class revenue allocation have failed to prove on the facts of this case that the Commission should reverse the Residential Class revenue apportionment carved out by the Commission over a series of Minnesota Power rate cases. These parties have made no effort to establish that the Large Power class customers impose any less of a risk on the MP system as compared to the Company's 1987 rate case or previous rate cases. This record establishes that the Residential Class is facing financial hardships (particularly low income customers) that have worsened since the Company's 1987 rate case. While Minnesota Power has made substantial efforts to give rate relief to assist its Large Power Class customers, the Company has made no similar effort for the Residential Class customers. Large Power Class customers have received and are continuing to receive rate relief from Minnesota Power.' For example, at the time of the 1987 rate case, Large Power revenues constituted approximately 61% of Minnesota Power's total revenues, however, based on Minnesota Power's

cost of service study in this proceeding, Large Power revenues are approximately 53% to 54% of total revenues. There has been a reduction in revenue per kwh of approximately 14% since 1988. Large Power Class customers will receive a 5-7% savings in rates as a result of the Peabody coal buy-out and the Burlington Northern renegotiation. Beginning in 1993, Minnesota Power offered large power customers interruptible service at a $5.00 per kilowatt-month discount in exchange for lengthened contract commitments. Minnesota Power will be providing the Large Power customers a total discount of $6 million per year. Tr. Vol. 4, p. 79. In 1988, MP offered $12.5 dollars cash as incentive payments to large power customers in return for contract extensions.

188. Revenue reductions to the Large Power Class will continue as a result of this proceeding and as a result of the rate relief identified above. This overall reduction in rates to the Large Power Class is another reason for the need for quantification of the cost of the risk for serving the Large Power Class.

189. It is reasonable and appropriate to apply the required revenue increase percentage (6.58%) evenly across the board to Residential, General Service, Large Light and Power, Large Power, Municipal Pumping and Lighting Classes. The reduction in revenue requirement due to the National Stipulation should be handled in the same manner.

DISCUSSION

The Judge rejects all the proposals that call for a dramatic increase In Residential Class revenue responsibility. Not one of these proposals is reasonable, moderate or consistent with prior Commission decisions. Indeed, these proposals call for a major policy reversal by the Commission. It is curious that the parties requesting this "policy reversal" have made no requests that the Commission reconsider and reverse its previous policies. Instead, the parties simply ignore previous Commission decisions.

It should be noted that the underrecovery of revenue from the Residential Class did not first appear during this rate proceeding. The Residential Class revenue responsibility has been developed by the Commission in its previous decisions. In those decisions, the Commission attempted to place revenue responsibility on the Large Power Class consistent with the costs of attracting or keeping investors because of the risks of serving the Large Power Class. The additional monies were used to reduce the Residential Class revenue responsibility. The Residential Class revenue apportionment is a product of prior Commission decisions; accordingly, a major change in the Residential Class revenue responsibility requires that those Commission policies be reexamined. However, the parties proposing the dramatic change for Residential Class revenue responsibility have ignored prior Commission decisions.

The Judge believes that the proposal by the OAG for an even across-the-board application of the required revenue increase percentage is appropriate for this proceeding. Therefore, the Judge has recommended a 6.58% across-the-board increase to the non-interruptible customers identified above.

Many residential customers in Minnesota Power's service area have low incomes or are on fixed incomes. They already face financial hardship and will have difficulty paying the dramatic increase in power rates proposed by the parties in this case. Residents in Duluth have substantially lower incomes on average than the rest of the State of Minnesota, and this income gap has grown significantly since 1979. SF Ex. 63, p. 5. The average income in the 16 counties served by Minnesota Power is lower than the average income in Duluth and is 30% below the state average. OAG Ex. 117, p. 5. Since the Commission last set final rates for Minnesota Power in 1988, the public assistance case load in St. Louis County shows a 18% increase. SF Ex. 63, p. 6. Between the years 1980 and 1990, the percentage of the population living below the poverty level in Duluth grew by 38.3% and in St. Louis County by 60.9%, compared to 7.4% statewide. The percentage of the population over 65 years of age is significantly higher in MP's service territory than it is with the rest of the state. DPS Ex. 150. Many of these customers live on fixed incomes and have no ability to pay increased electric rates.

Small business customers are in Minnesota Power's General Service Class. Small businesses represent an extremely important sector of the economy in Minnesota Power's service territory. According to data from the U.S.

Department of Commerce, Bureau of Census, over 90% of the businesses and roughly one-third of all jobs in the region come from small businesses with fewer than 20 employees. OAG Ex. 116, pp. 14-15. The Bureau of Census data indicates that the county served in whole or in part by Minnesota Power contain approximately 14,000 to 16,000 small businesses providing approximately 65,000 jobs for residents in the region. MP Ex. 29, pp. 7-8, OAG Ex. 33.

The 18% increase proposed by Minnesota Power for the General Service Class would have a negative impact on the small business customers within the class. The proposed 18% increase would mean typical annual billing increases for average-sized users in the class ranging from hundreds to several thousands of dollars per year. OAG Ex. 116, p. 16. MP Ex. 50 (RJK), Schedule 12, p. 11. These small businesses must meet a payroll and must operate in competitive activities where they have very little ability to pass on higher costs to their customers. Under such circumstances, an increase in electricity prices would likely mean a reduction in income, in wages, and in employment.

One of the reasons Minnesota Power recommended such major increases to the Residential and General Service Classes was out of concern for the economic situation faced by its Large Power Customers. Large Power Customers face fierce and significant worldwide competition for the sale of taconite and paper products; a circumstance that Minnesota Power has no control over. However, Minnesota Power has made substantial efforts at reducing these customers' costs for electricity. While Minnesota Power's Large Power customers and Large Industrial customers face difficulties, so do the Residential and General Service Classes.

The Commission should consider the needs of Large Power Customers and the economic situation they face, just as the Commission should consider the same factors for Residential, Small Business and Large Light and Power customers. Minnesota Power's legitimate concerns for the well-being of its Large Power customers does not justify the disportionately large increases in residential and small business rates which Minnesota Power and others have recommended in this proceeding.

Minnesota Power's Large Power customers are important to northeastern Minnesota. These customers provide a major source of employment and economic activity in the region and there would be negative economic repercussions if these industries were to fail. OAG Ex. 116, p. 8. Large Power customers purchase large amounts of power for a high percentage of the hours in the year. This results in an unusually high load factor for the Company as a whole and in turn contributes to lower costs for all Minnesota Power customers. OAG Ex. 116, pp. 8-9.

Given these system characteristics and the competitive environment Large Power customers face, Minnesota Power is concerned that too large a rate increase would cause some of its Large Power customers to either go out of business or leave the system, driving up rates to remaining customers. The large power customers themselves similarly state that rates set too high will force them to close or leave the system.

Despite the concerns raised by Minnesota Power and Large Power customers, the record does demonstrate some positive indications regarding the economic situation faced by Large Power customers. While these customers do not have, at this point a robust business environment, taconite production has increased substantially since 1986 levels. MP Ex. 28, p. 5. According to the Company's economic load forecast, the taconite and paper industries will show "relative strength" in the forecast period. MP Ex. 38 (SDS) Schedule 1.

In assessing the need for a disproportionate low rate increase for the Company's large industrial customers, the Commission must also consider the tools Minnesota Power has for addressing these customers' needs outside of the rate case process. For example, since 1988 Minnesota Power has offered cash incentive payments to Large Power customers in return for contract extensions. MP Ex. 28, pp. 7-8. In 1993, MP also began offering Large Power customers interruptible service at a discount of $5.00 per KW-month, again in exchange for lengthened contract commitments. Field cost reductions achieved by Minnesota Power through the Peabody Co. buyout and the Burlington Northern renegotiation will significantly lower the energy bills of Large Power customers by approximately 5% to 7% while lowering residential bills by roughly 2%. There has been a reduction in the average revenue per kwh for the large power class of approximately 14% since 1988. Minnesota Power's CCOSS indicates that revenues from large power customers constitute approximately 53% of total revenues as compared to approximately 16% of total revenues last rate case proceeding in 1987.

D. Class Rate Design

1. Residential Class

190. Minnesota Power proposed to maintain the same general structure for the residential rate, including the "life line" feature for 350 kWh of usage and a very low customer charge which incorporates the first 50 kWh of usage. Minnesota Power proposes to increase the customer or service charge slightly more than the other energy blocks in the interim and final rate increases. (MP Ex. 51, pp. 22-23). The entire amount of the rate increases proposed for 1996 and 1997 are incorporated in the customer charge, which will go up by $1.34 per month each of these years. (Id. at 23).

191. Minnesota Power has proposed a 33% increase in the "life line" rate. The minimum bill is proposed to be increased by 88%. As a result of the Company's proposal, Minnesota Power will go from being the least expensive Minnesota electric utility at the lowest consumption level (100 kwh) to the highest or most expensive Minnesota electric utility at the 100 kwh consumption level. MP Ex. 51, RJK Schedule 16.

192. Thirty-five percent of MP's residential customers are eligible for low-income benefit programs due to their lack of adequate income. SF Ex. 63, p. 21. The Duluth and northeastern Minnesota area is losing ground with respect to other parts of the state; increases in income are slower for this area as compared to other parts of the state. The area has had a rise in the unemployed and an increase in elderly households. The increase in the number of persons living at the poverty level exceeds the national average and exceeds other parts of the state of Minnesota. A low income assistance program along the lines of that contemplated by 1994 Minn. Laws ch. 641, art. 4, sec. 3 would be appropriate for the Minnesota Power service area, particularly in connection with a proposal for a major increase in the rates of low-income ratepayers.

193. The Minnesota Power Residential Class rate structure proposal that places most of the rate increase on a front end demand charge adversely affects low-income ratepayers more than other residential ratepayers. The rate structure should be revised so as to lessen the impact on low-income ratepayers and more reasonably share the increase with those residential ratepayers who are more able to pay. The low life line rate should be preserved for low income customers.

194. As a part of any future rate case filing that contains large increases for the Residential Class, the Company should also file a plan for reducing the impact of the increases on low-income residential customers.

DISCUSSION

Over the past several rate cases the Commission has preserved a low life line rate for low-income residential ratepayers. However, in this proceeding, Minnesota Power has proposed a 33% increase in the life line rate. In light of 1994 Minn. Laws ch. 641, art. 4, sec. 3, which encourages public utilities to propose low-income assistance programs, it is unreasonable for the Company to propose large increases in Residential Class rates and not build in a safety net for low-income customers. The Company's justification (that the actual dollar amount is modest) suggests that the Company has not heard the concerns of fixed and low-income seniors and other ratepayers who may be forced to make undesirable life choices as a result of a large increase in rates. The Judge recognizes that not all residential customers need assistance. Under MP's proposal, low-income customers are more adversely affected than customers who need no assistance. Had the Company proposed a safety net for low-income ratepayers, the proposed increase would have been more reasonable on this issue.

The Judge notes for Commission consideration that the Comission should encourage continued participation in Minnesota Power rate cases by representatives of low-income consumers. The participation in this proceeding by the Senior Federation has been helpful to the Judge, particularly on the rate design recommendations in this case.

195. The Company recommended that Rate Areas I, II and III be

consolidated into a single rate area. Rate Area I is for the City of Duluth, Rate Area II for urban areas other than the City of Duluth, and Rate Area III is for rural areas. The current rate levels vary slightly by Rate Area. The Company believes the elimination of the three distinct Rate Areas would achieve rate simplification and reduce administrative costs. (MP Ex. 50, p. 27).

196. The Administrative Law Judge rejects Minnesota Power's Rate Area consolidation proposal. The Company has not offered affirmative evidence that substantiates its claims that the cost of serving the different rate areas are the same, or that the proposed consolidation will reduce costs.

2. General Service Class

197. Minnesota Power proposed that the 18% increase to the General Service Class be implemented with a slightly greater percentage increase in the customer charge and demand charge than in the energy charge. (MP Ex. 50,

p. 29). The Company also proposed consolidation of the three Rate Areas for General Service, for the same reasons that it proposed consolidation for Residential Service. (Id.) The Company also proposed to increase the discount for high voltage service, to more closely track the differential in costs. (MP Ex. 50, p. 30).

198. The Judge has already rejected the proposed 18% increase to General Service Class rates as being inappropriate and unjustified by the facts in this proceeding. The Company's proposed consolidation of three Rate Areas for General Service Class has the same problem as that of the consolidation of Rate Areas in the Residential Class. The Company has failed to meet its burden of proof that the consolidation is reasonable for ratemaking purposes.

3. Large Light and Power Class

199. The Company proposed to introduce the new Interruptible Service Rider to the General Service and Large Light and Power Service Classes. (MP Ex. 50, pp. 31-32 and MP Ex. 122). The Rider provides General Service and Large Light and Power customers an option to receive interruptible service in exchange for a 20% discount of their bill based on the Company's standard rates. The rider was intended to offer customers with loads over 200 kW an opportunity to take interruptible service as an alternative to the dual fuel interruptible service, which service the Company proposes to discontinue. (MP Ex. 50, p. 32).

200. The Company proposed to increase commercial dual fuel rates by 46%, to more closely reflect current costs and market conditions; to close them to new customers having connected interruptible loads over 200 kW as of November 1, 1994; and to discontinue this service to existing loads over 200 kW as of December 31, 1999. (MP Ex. 50, pp. 32-33).

201. The Company's proposals for the commercial dual fuel rate and the introduction of the Interruptible Service Rider are reasonable and appropriate and should be adopted by the Commission.

DISCUSSION

The DPS and LLP opposed the changes to the commercial dual fuel rate on the basis that none of the changes was cost justified by Minnesota Power. The Company admitted that it did not have cost justifications for the proposed changes in the commercial dual fuel rate. Ordinarily, the Judge would have rejected the Company's proposal based upon this admission. However, on closer review, the Judge is persuaded that Minnesota Power has offered a reasonable justification for its proposals.

The Company's recommendation to eliminate the dual fuel rate is not based upon cost of service considerations; rather, it is based upon the significant risk of revenue erosion which could occur to the Company if Large Light and Power customers move to that rate rather than to a more cost justified interruptible service rate. (MP Ex. 29, p. 4). Mr. Harmon testified that the Company has seen significantly increased competitive pressure in the last 18 months for customers to transfer to the dual fuel rate, as developers from outside the service area approached customers and offered contractual arrangements where a third party will provide backup generation and the customer would see benefit from switching to the dual fuel rate. (Tr. Vol. 2, pp. 205-206). This concern about revenue erosion is not insignificant. About 1o customers who have already indicated to Minnesota Power that they are seriously considering installation of their own generation to to take advantage of a dual fuel rate. If those 10 customers were to switch to the dual fuel rate, this would represent nearly $900,000 of revenue erosion per year. (Tr. Vol . 2, p. 206 and Tr. Vol. 4, pp. 120-121). If the rate remains open, it would be reasonable to conclude that this kind of migration to the dual fuel rate would continue and revenue erosion would increase.

4. Large Power Class

a. Non-Contract Rate

Minnesota Power proposed to reinstate the Non-Contract Rate approved in the 1987 rate case. The non-contract rate addresses those situations in which a Large Power customer is unable to enter into a service agreement meeting the minimum notice and term requirements of the Large Power Service Schedule. The non-contract Large Power Service Schedule 58/78 was applicable to any customer having requirements of at least 10 MW who was unable to make long-term contractual commitments. (MP Ex. 50, p. 34). On Schedule 58/78, the demand charges and service voltage adjustments would be 120% of the charges proposed in the standard Rate Schedule 54/74, whereas the energy charges would be equal to the energy charges in Schedule 54/74 (Id.) The DPS adopted the Company's proposal for reinstatement of the Non-Contract Rate.

The Administrative Law Judge finds that reinstatement of the Non-Contract Rate is reasonable and appropriate and should be adopted.

DISCUSSION

Eveleth and Potlatch are opposed to the Non-Contract Rate; both consider it a 20% penalty to customers unable or unwilling to enter long-term take-or-pay commitments. Potlatch asserted that take-or-pay requirements are already in place to an unusual degree within the MP system and that an additional such requirement should not be adopted.

Eveleth has given its notice of contract cancellation, having been unwilling to continue the risk of take-or-pay contract obligations. Eveleth may find itself in a position where the contract rate if adopted may be applied to it. Eveleth argues that the degree of revenue stability sought by Minnesota Power "is not attainable without imposing on its customers a greater instability".

After consideration of these arguments, the Judge has recommended adoption of the proposed Non-Contract Rate for the following reasons. In the Company's 1987 rate case proceeding, the Commission found that it was reasonable to provide an alternative rate for Large Power customers who declined to commit to the standard long-term rate requirements. The Commission went on to conclude that the premium cost was necessary because the absence of long-term demand commitments from Large Power customers increases the financial capital costs of Minnesota Power and may cause costly capacity planning decisions. The Judge believes that the Non-Contract Rate and its requirements contained to be reasonable and should be reinstated.

b. Excess Demand Discount

DPS recommended that Minnesota Power eliminate the Excess Demand Discount. DPS Ex. 99, p. 8. The Excess Demand Discount had been proposed in 1987 as a means of marketing excess capacity. Because the Company no longer has capacity surpluses, the Excess Demand Discount was no longer necessary. Minnesota Power opposed DPS's recommendation, indicating that Large Power customers use the Excess Demand Discount for planning purposes and desire that the Excess Demand Discount remains available to them.

The Judge finds that it is reasonable and appropriate to continue the Excess Demand Discount.

DISCUSSION

The Judge has considered and rejected the recommendation of the DPS. The Excess Demand Discount should not be eliminated for the reasons advanced by Minnesota Power, which the Judge adopts as his own.

The Excess Demand Discount continues to be necessary to encourage sales to utilize existing generating capacity, to encourage incremental taconite and wood product production in Minnesota and to provide flexibility to customers to adjust to changed production requirements. (MP Ex. 39, p. 2). Because of the availability of the Excess Demand Discount, Large Power customers have been making decisions to engage in incremental production that might not otherwise have occurred in their facilities or in Minnesota. (Id.) These decisions to engage in incremental production mean more revenue to Minnesota Power, thus reducing the revenue requirement for other classes. Such decisions also lead to more tax revenue for state and local government and more jobs for the general public. (Id.)

DPS contended that the flexibility needed by Large Power customers to use excess demand, without increasing their contract demand levels, could be obtained without the discount. While this may be true as to flexibility, it does not address the desirability of providing an incentive to Large Power customers to make incremental production decisions, as described above. (Tr.

Vol. 2, p. 235; Tr. Vol. 3, pp. 95, 104).

None of the Large Power customers want to have the Excess Demand Discount eliminated. (Tr . Vol . 3, p . 106, lines 8-11; Tr. Vol. 2, pp. 256-257). Since all other classes of customers are revenue neutral, and the impacts of the excess demand discount are worked out strictly through the Large Power rates, the support for the Excess Demand Discount by Large Power customers should be recognized. Since this is simply an intra class rate design issue, and the Large Power customers have relied upon the Excess Demand Discount in planning their operations and in establishing long-term contract levels of demand, it would be inappropriate to eliminate it. (Id. MP Ex. 39, pp. 1-3; Tr. Vol. 6, P. 8).

c. LP Demand Ratchet and Measured Demand

Large Power Intervenors have recommended adjustments to the Large Power Demand Ratchet and modifications of the Measured Demand. Upon consideration of these proposals, the Judge does not believe the recommendations should be adopted. Large Power Intervenors proposed to modify the billing demand ratchet provision In the Large Power tariff to reduce the demand charge by $4.50 per kW month for any "unused demand" which is not actually used but for which the Large Power customer must make payment under the 100% demand ratchet. (LP Ex. 133, p. 42). This concept of "unused demand" would introduce considerable risk of revenue instability and unrecovered fixed costs for the Company. (MP Ex. 51, p. 26). The 100% billing demand ratchet was designed in recognition of the fact that Minnesota Power's fixed costs remain the same whether customers are operating or not. (MP Ex. 39, p. 6). Nothing has changed to warrant any reduction in that regard. The proposal should be rejected.

Large Power Intervenors recommended modification that measured demands be determined on the basis of the highest customer use during the Company's peak period of each month, rather than based on the customer's highest 15 minute demand occurring any time during the month. (LP Ex. 133, pp. 46-47). Existing Large Power customers presently have peaks that often occur in the off-peak periods. (MP Ex. 39, p. 7). LP's proposal would result in reduced billing demand for Large Power customers since the higher off-peak loads would not be considered for billing purposes. (Id.) This would present a further risk that customer operations would be changed to shift on-peak use to off-peak periods, further reducing billing demands and further reducing revenues. (Id.) The Large Power Intervenor proposal should not be adopted.

d. Large Power Contract Terms

Eveleth and the Large Power Intervenors proposed that the contract terms for Large Power Service be revised. Eveleth recommends a reduction of the cancellation notice period from four years to one year. Large Power Intervenors recommend that Large Power customers' ten-year initial contract term and accompanying four-year cancellation notice period be reduced to a five-year initial term and a one-year cancellation notice period. The Judge has considered these proposals and rejects them for the following reasons. The four-year cancellation notification requirement provides critical input into Minnesota Power's load forecasting, bulk marketing and resource planning efforts. (MP Ex. 39, pp. 8-9). It also serves as a gauge by which financial markets assess the Company's future revenues. (Id. at 9) Further, the reduction of the initial term from 10 years to 5 years assumes that growth conditions, similar to those existing in the 1970's, will not reoccur. (Id.) Further, flexibility exists under the current rates for Minnesota Power to provide for shorter term initial contracts, with Commission approval, for a new Large Power customer who did not require significant capital investment in facilities. (MP Ex. 39, p. 9). Finally, any reduction in the contract terms would necessarily increase Minnesota Power's risk and would result in higher return on equity requirements, with correspondingly higher rates. (MP Ex. 39, P. 10).

CONCLUSIONS

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of the hearing pursuant to Minn. Stat. Ch. 216B and 14.57 - 14.62, and Minn. Rules 1400.5100 - .8300.

2. The Commission gave proper notice of the hearing in this matter, has fulfilled all relevant substantive and procedural requirements of law or rule and has authority to take the action proposed.

3. Any of the foregoing Findings more appropriately considered Conclusions of Law are hereby adopted as such.

4. The proper test year for determining Minnesota Power's revenue deficiency is the 12-month period between January 1, 1994 and December 31, 1994.

5. The following conclusions regarding revenues do not include the effect of the National Stipulation.

6. The appropriate test year representative rate base to be used for this proceeding is $484,254,999.

7. The appropriate test year representative operating income for the Company is $30,319,000.

8. The appropriate rate of return on common equity is 10.7%. Based upon the test year representative capital structure, the appropriate overall rate of return is 8.88%.

9. The Company's test year revenue deficiency with SFAS 106 is $21,631,998. Thus, the Company is entitled to an increase of $21,631,998 or 6.58% in annual revenues, not including the National Stipulation.

10. The Company's Class Cost of Service Study should be adopted.

11. The reserve deficiency should be collected by an across-the-board application of the required revenue increase percentage 6.58% to the following Minnesota Power rate classes: Residential, General Service, Large Light and Power, Large Power, Municipal Pumping and Lighting.

THIS REPORT IS NOT AN ORDER AND NO AUTHORITY IS GRANTED HEREIN. THE PUBLIC UTILITIES COMMISSION WILL ISSUE THE ORDER OF AUTHORITY WHICH MAY ADOPT OR DIFFER FROM THE FOLLOWING RECOMMENDATIONS.

It is the Recommendation of the Administrative Law Judge to the Public Utilities Commission that it issue the following:

ORDER

Within thirty (30) days of the date of this Order, Minnesota Power & Light Company shall file with the Commission for its approval, and provide to all parties to this proceeding, a revised schedule of rates and charges incorporating the decisions made herein, so as to allow the production of increased annual revenues for the test year equal to the revenue deficiency herein, in accordance with the rate design provided for herein.

Within thirty (30) days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties to this proceeding, a proposal torefund to its customers any monies collected in interim rates which are in excess of the increase in interim rates authorized herein.

This Order shall become effective immediately.

Dated this 20th day of September, 1994.

ALLEN E. GILES
Administrative Law Judge